STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM PURSUANT TO IND. CODE § 8-1-2-42(a) TO (A) TIMELY RECOVER CHARGES AND CREDITS FROM REGIONAL TRANSMISSION ORGANIZATIONS AND NIPSCO'S TRANSMISSION REVENUE REQUIREMENTS; (B) TIMELY RECOVER NIPSCO'S PURCHASED POWER COSTS; AND (C) ALLOCATE NIPSCO'S OFF SYSTEM SALES REVENUES; (6) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS, THE ENVIRONMENTAL COST RECOVERY MECHANISM AND THE ENVIRONMENTAL EXPENSE MECHANISM; (7) APPROVAL OF THE CLASSIFICATION OF NIPSCO'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; AND (8) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.* TO THE EXTENT SUCH RELIEF IS NECESSARY TO EFFECT THE RATEMAKING MECHANISMS PROPOSED BY NIPSCO.	CAUSE NO. 43526 FILED AUG 2 9 2008 INDIANA UTILITY REGULATORY COMMISSION

Prepared Direct Testimony and Exhibits

of

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Volume 6 of 6

John J. Reed, Victor F. Ranalletta, Bradley K. Sweet, Curtis A. Crum, Kelly R. Carmichael

August 29, 2008

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Petitioner's Exhibit JJR-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

JOHN J. REED

CHAIRMAN AND CEO

CONCENTRIC ENERGY ADVISORS

SPONSORING PETITIONER'S EXHIBITS JJR-2, JJR-3 AND JJR-4

VERIFIED DIRECT TESTIMONY OF JOHN J. REED

I. INTRODUCTION AND BACKGROUND

Q1. Please state your name, job title, employer and business address.

A1. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q2. By whom are you employed and in what capacity?

A2. I am the Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc. and CE Capital Advisors (together "Concentric").

Q3. What is your background and experience in the energy and utility industries?

A3. I have more than 28 years of experience in these industries, having served as an executive in consulting firms and as Chief Economist for the nation's largest gas utility. I have advised more than 100 utility clients over the course of my career on a wide range of strategic, economic, financial and regulatory issues. My experience is described in more detail in Petitioner's Exhibit JJR-2.

Q4. Have you previously appeared before this Commission?

A4. Yes. Most recently, I served as an expert witness before the Indiana Utility Regulatory Commission ("IURC") on behalf of Northern Indiana Public Service Company ("NIPSCO" or the "Company") in support of the reasonableness of the purchase price for the Sugar Creek generating station (Cause No. 43396). I also provided testimony on behalf of NIPSCO with respect to the fair market value of NIPSCO's generation, transmission and distribution assets in the context of the IURC's 2001 electric rate investigation (Cause No. 41746).

Q5. Have you appeared as an expert witness in other energy or utility proceedings?

A5. Yes. I have provided expert testimony on economic and financial issues related to the energy and utility industry on dozens of occasions before administrative agencies, courts, arbitration panels and elected bodies across North America. A listing of my recent appearances as an expert witness is provided in Petitioner's Exhibit JJR-3.

Q6. Please describe Concentric's activities in energy and utility engagements.

A6. Concentric provides financial and economic advisory services to a large number of energy and utility clients across North America. Our financial advisory activities include merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services and transaction support services. Our economic and market analysis services include energy market assessment, market entry and exit analysis, utility ratemaking and regulatory advisory services, and energy contract negotiations.

II. PURPOSE OF TESTIMONY AND CONCLUSION

Q7. What is the purpose of your testimony?

A7. I have been asked by NIPSCO to provide an assessment of the fair market value of its electric generation facilities using the discounted cash flow methodology ("DCF Approach" or "DCF"). The purpose of my testimony is to discuss how I used the DCF

Approach to value NIPSCO's electric generation assets and the conclusions reached from the use of that methodology. NIPSCO Witness John P. Kelly, an Executive Advisor at Concentric, will address the value of NIPSCO's electric generation assets on the basis of Replacement Cost New Less Depreciation ("RCNLD"). Mr. Kelly will also address the RCNLD value of NIPSCO's transmission, distribution, general and common plant assets.

Q8. What generation assets have you valued?

A8. I have performed fair market valuations for each of the following generation assets -- Bailly Units 7, 8 and 10; Michigan City Unit 12; R. M. Schahfer Units 14, 15, 16A, 16B, 17 and 18; and the Norway and Oakdale generating stations ("the NIPSCO Generation Assets").

Q9. What conclusion have you reached regarding the fair value of NIPSCO's generating assets?

A9. In my opinion, the fair value of the NIPSCO Generation Assets using the DCF Approach is $2.3 billion.

III. DESCRIPTION OF THE NIPSCO GENERATION ASSETS

Q10. Please describe each of the generation stations that you have valued.

A10. Petitioner's Exhibit JJR-4 provides an overview of the NIPSCO Generation Assets. Specifically, Petitioner's Exhibit JJR-4 presents the name, location, capacity, fuel type, date of commercial operation, and assumed useful life for each of the facilities. This Exhibit also provides the DCF value that I have calculated for each of these facilities.

Q11. What generating stations have been excluded from your valuation?

A11. I excluded the D.H. Mitchell Generating Station and Michigan City Units 2 and 3 from my valuation because I was advised NIPSCO intends to retire these facilities.

Q12. What records, information and data about the NIPSCO Generation Assets did you review in order to develop an opinion about their value?

A12. I have reviewed an extensive amount of historical and projected information related to each of the facilities, including output, operating cost data, environmental performance, age, location, and capital expenditures.

Q13. Have you physically inspected each of the generation facilities?

A13. I have recently inspected all of the NIPSCO Generation Assets for the purpose of preparing a valuation of each facility based on its individual operating characteristics. As part of my evaluation, I have discussed the operations of each of the facilities with the plant personnel to determine whether there are any material factors that would need to be considered as part of my overall valuation.

Q14. When did you perform your physical inspection of the NIPSCO Generation Assets and what were your general observations regarding the usefulness of the facilities?

A14. On May 15, 2008, I conducted field observations of the generation facilities to observe their condition. These observations included plant walk-throughs, discussions with plant staff, and a review of operating and maintenance practices. This review was undertaken to observe the condition of the generation facilities and to re-acquaint myself with the units. In general, I found the NIPSCO Generation Assets to be in good operating condition, consistent with other units of their vintage and design.

Q15. Based on your study and inspection, do you have an opinion as to whether the NIPSCO Generation Assets are used and useful in the provision of electric utility service?

A15. Yes. In my opinion, all of the NIPSCO Generation Assets included in my valuation are used and useful and reasonably necessary in the provision of reliable electric utility service by NIPSCO to its customers.

Q16. In your opinion, have you studied the NIPSCO Generation Assets in sufficient detail to render an opinion as to their fair value?

A16. Yes.

IV. DCF APPROACH

Q17. How is the DCF Approach defined?

A17. The DCF Approach (also known as the Income Approach) is defined as the measurement of "the present value of the future benefits of property ownership."[1] The DCF Approach is utilized to value all types of revenue producing assets (such as electric generation facilities) and is applicable to all types of businesses, including utilities. The DCF Approach uses the discounted cash flow model to quantify the present value of the expected future cash flows to be generated from an asset over a specified period of time

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[1] The Appraisal of Real Estate, Eleventh Ed., Appraisal Institute, 1996, p. 91.

plus any residual (or resale) value, and less any demolition costs that that asset may have at the end of the specified time. While the most significant element of value for an income producing property or asset is the present value of the expected future cash flow, the residual value for the asset, if any, must also be considered in the valuation of the asset. The premise of any DCF analysis is that the value to an investor of an asset or investment is the cash that is able to be derived from owning that asset or investment.

Q18. What are the advantages of using the DCF Approach?

A18. The primary advantage of the DCF Approach is that it provides the framework in which the numerous benefits and risks of the specific assets being valued – and thus the future ongoing economic value of those assets – can be quantified. Conducting a DCF analysis is an element of any due diligence effort when a potential purchaser is evaluating an income-producing asset.

Q19. What are the other primary approaches to valuation?

A19. The other primary approaches are the Sales Comparison Approach (valuing an asset by considering the sales prices in transactions involving the sale of comparable assets) and the Current Cost Approach (valuing an asset by considering its replacement cost, adjusted for its current condition). While the applicability of each of these measures depends upon the nature of the asset, one or more of these approaches often are used to make an independent third-party evaluation of an asset's value. Mr. Kelly will testify as to the value of the NIPSCO Generation Assets using the RCNLD Approach, which is a form of the Current Cost Approach.

Q20. Why did you not use the Sales Comparison Approach?

A20. While the DCF refers to a great number of forecasted variables that are specific to the subject assets, the Sales Comparison Approach refers specifically to the subject assets primarily in terms of generation capacity. To use the Sales Comparison Approach it is necessary to find examples of asset sales that match the asset being valued. Because a direct match is rarely available, the Sales Comparison Approach result normally must be adjusted to reflect a premium or discount due to differences between the comparables group and the subject assets. I have relied on the DCF for the purpose of valuing the NIPSCO Generation Assets in order to provide a direct and specific estimate of value.

Q21. Please explain how you have conducted the DCF Approach.

A21. The fair market value of an asset is "the price that property would sell for on the open market. It is the price that would be agreed on between a willing buyer and a willing seller, with neither being required to act, and both having reasonable knowledge of the relevant facts."[2] I have developed a DCF model to calculate the value to a buyer that would be derived from the projected after-tax operating cash flows that would be generated by each of the NIPSCO Generation Assets during their remaining useful lives, assuming also that their electric energy were to be sold at market-based prices. In my study, I have used a valuation date of December 31, 2007.

In very simple terms, net operating cash flow for each plant is essentially calculated as follows:

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[2] Source: Internal Revenue Service, Publication 561.

Energy Revenue (at market-based prices)
- Dispatch Cost (including fuel, emissions allowances and variable operating expenses)
- Fixed Costs (including fixed operating expenses, administrative and general expenses, insurance and property taxes)
- Income Taxes

Net Operating Income
- Capital Expenditures

Net Operating Cash Flow

The DCF Approach uses assumptions based on the historical operating experience of the NIPSCO Generation Assets as well as projected future market conditions in order to project the net operating cash flows over the complete useful lives of each of the generating units.[3] Demolition cost estimates were provided by the Company based on studies performed by Burns & McDonnell Engineering Company, Inc., and these costs were deducted from the cash flows at the end of each unit's useful life. The total DCF value of the assets is the sum of the present value of the Net Operating Cash Flow, less the demolition cost.

Q22. What did you assume to be the useful life of the NIPSCO Generation Assets?

A22. I assumed the same retirement schedule that was provided in the Company's 2007 Integrated Resource Plan.[4] Column H of Petitioner's Exhibit JJR-4 provides a complete listing of the useful lives that I have assumed.

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[3] Unlike the gas and coal-fired units, which are modeled through their expected useful lives of 40 and 60 years from their respective in-service dates, Norway and Oakdale are assumed to have perpetual useful lives provided that sufficient capital expenditures are provided for maintenance. I have modeled Norway and Oakdale explicitly for only the next twenty years. The remaining cash flows for these units are capitalized by multiplying the Year 20 cash flow by a capitalization rate of 14.1x. I have calculated the capitalization rate using the Gordon Growth model, assuming zero real growth.

[4] See Northern Indiana Public Service Company – 2007 Integrated Resource Plan submitted to the Indiana Utility Regulatory Commission, Table 7-4.

Q23. What are the key assumptions that are included in the DCF Approach?

A23. The key assumptions in the DCF Approach include forward energy market price projections, general inflation and discount rate assumptions that were applied across all units, and specific operating and financial statistics for each unit.

Q24. Please describe the source of your energy price forecast.

A24. I relied on a 20-year energy price forecast for each plant, which was provided to me by Ventyx. This forecast was developed using a detailed production costing model. I reviewed the assumptions and the methodology behind this forecast and found them to be reasonable and reliable.

Q25. Please describe Ventyx.

A25. Ventyx is a leading provider of utility industry solutions for generation asset and portfolio optimization, energy trading and risk management, schedule management, price and load forecasting, maintenance optimization, resource planning, fuel budgeting, plant betterment and environmental compliance analysis. With offices in North America, Europe, the Middle East and Asia-Pacific, Ventyx has more than 700 clients in select asset-intensive service-based industries.

Ventyx provides electricity market modeling services through a business line that was formed through the 2007 acquisitions of NewEnergy Associates, LLC ("NewEnergy") and Global Energy Decisions ("GED"), both of which were leading companies in this area. Together as Ventyx, the companies hold a prominent position in electricity market

Regulatory Commission, Table 7-4.

forecasting, serving a multitude of electric utilities, investors, banks and others with market forecasting services in the context of strategic planning, valuation, and mergers and acquisitions.

Q26. What experience does Ventyx have in developing energy price forecasts?

A26. Before its acquisition by Ventyx, NewEnergy provided forecasting services to electric and gas utilities and their investors and consultants for more than 30 years, and staff from NewEnergy performed the market forecasting services that stand behind the Company's 2007 Integrated Resource Plan (the "2007 IRP"). NewEnergy developed the PROMOD market forecasting software, which has been used extensively in the energy industry, and was part of the software package used in the forecast that was provided to me by Ventyx.

Before its acquisition by Ventyx, GED was also a leading provider of energy forecasting services to utilities, their investors and consultants for more than 30 years. GED's electricity market forecasting strength was derived in part through its 2002 acquisition of Henwood Energy Services. Henwood Energy Services developed the PROSYM and MARKETSYM software packages, which have also been used extensively in the energy industry and were part of the software package that was used in the forecast that was provided to me by Ventyx.

Q27. Is Ventyx a reasonable and reliable source of energy market forecasts for purposes of financial analysis and valuation?

A27. Yes, it is.

Q28. What was Ventyx's approach?

A28. Ventyx used a two-step approach. First, it calculated a price forecast for the load zone in which the NIPSCO Generation Assets are located. It then used a more detailed model to calculate the specific locational marginal price ("LMP") for each of the NIPSCO plants.

In the first step, Ventyx used its Electricity and Fuel Price Outlook, Midwest, Spring 2008 (the "Reference Case"), a zonal electricity price forecast. Using the MARKETSYM electric price projection model, the Reference Case provides a forecast of electricity prices for each major load zone in the footprint of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") for each month from May 2008 through December 2032. The Reference Case is one of a series of semi-annual zonal forecasts published by Ventyx that is widely referred to by buyers and sellers of generation assets, including generation asset purchases and sales, market assessments, and generation project financing.

However, because MARKETSYM only calculates at the resolution of a load zone, it does not provide a forecast of prices or capacity factors for specific generating units. Therefore, Ventyx used the MarketWise feature within PROMOD to forecast the unit-specific dispatch and pricing as it would actually take place in the Midwest ISO market. Using a forecast of dispatch costs for specific units that was provided by NIPSCO, MarketWise calculates the specific price and capacity factor that would be received by each unit according to its unique ability to bid into the competitive Midwest ISO marketplace at the prices provided by the Reference Case. MarketWise also considers the effects of transmission congestion on these unit-specific prices. This approach is an updated version of the market price projection that NIPSCO used in its most recent power supply solicitation as well as its 2007 IRP.

Q29. How did you account for the fact that there have been several months of actual operations of the NIPSCO Generation Assets since the valuation date?

A29. I have used actual generation data for the NIPSCO Generation Assets for the period of January 1, 2008 through April 30, 2008 for purposes of my DCF analysis. I refer to the Ventyx forecast for the forecast period beginning May 1, 2008.

Q30. Why is a market-based pricing model appropriate when the NIPSCO Generation Assets are still subject to regulation?

A30. As noted above, the purpose of my analysis is to determine the fair market value that would be given to the NIPSCO Generation Assets in a free, competitive market. In other words, for purposes of this approach, I have assumed that fair value ratemaking would replicate the value of the property in a competitive, non-monopoly marketplace. This approach is also consistent with one of the traditional principles of valuation, *i.e.*, that a property or asset should be valued based on its highest and best use. This valuation can only be done if revenues are based on competitive market prices, not regulated rates. If regulated rates are used to determine revenues, the approach can become circular, because future income will depend upon the rates authorized by the regulator.

Q31. How is it possible to determine market-based prices for a regulated commodity like electric energy?

A31. Because of the formation of competitive power markets, it is now possible to value electric utility property using a forecast of generation market prices. Sales of energy at market-based prices take place on a regular basis throughout the country. Therefore, it is now possible to determine the current and projected future market price of electric energy in each region of the country. These developments make it possible to use the DCF model to value the NIPSCO Generation Assets.

Q32. Did you assume that the NIPSCO Generation Assets would receive capacity revenues as well as energy revenues?

A32. I have conservatively not taken capacity value into account. If I had included capacity value, my resulting DCF value would have been higher.

Q33. What was your source for the forecast operating assumptions used in the analysis?

A33. For the forecast period from May 1, 2008 forward, I assumed the same forecast operating expenses in the financial forecast that Ventyx assumed in the MarketWise analysis. These assumptions, which include unit-specific heat rates, fuel costs, emissions rates, and fixed and variable operations and maintenance costs, were all provided by the Company. I reviewed these forecasts for reasonableness based on the historical performance and financial results of the NIPSCO Generation Assets. For the January 1, 2008 through April 30, 2008 forecast period, I referred to the same fixed and variable operating assumptions that were provided by the Company to be used in the Ventyx forecast.

Q34. What assumptions did you make with respect to general inflation?

A34. I adopted the Company's assumed general inflation rates used in a recent fossil asset management study conducted by the Company, as did Ventyx. The assumed inflation rate is approximately 2% per year, varying slightly from year to year. I found this forecast to be on the low side of a reasonable range of possible forecasts. I used these general inflation rates to escalate fixed and variable operating and maintenance expenses, property taxes, insurance, and capital expenditures in periods beyond the Company's explicit forecasts for these items. Fuel cost escalation was captured in separate explicit forecasts for each fuel.

Q35. Were administrative and general expenses included in the valuation of each plant?

A35. Yes. Using an average of the values provided in the Company's 2006 and 2007 Federal Energy Regulatory Commission ("FERC") Forms No. 1, I allocated administrative and general ("A&G") expenses between generation and transmission and distribution based on the assets of those segments. Then, I allocated generation-related A&G costs to each plant based on its gross margin. Finally, I escalated these values using the inflation rates I noted earlier.

Q36. Please explain the assumptions made with respect to environmental emissions.

A36. I calculated environmental emissions as the product of the NO_x, SO_2 and CO_2 emissions rates and the total forecast generation for each unit in a given year for each effluent. The total emissions of NO_x and SO_2 emissions were then compared to the Company's banked emissions allowances along with annually distributed allowances as established by the

United States Environmental Protection Agency ("EPA"). I found that the banked NO_x and SO_2 allowances allocated to the NIPSCO Generation Assets, together with annual allocations, were sufficient to cover all allowance requirements for those effluents throughout the forecast period.

Q37. The Clean Air Interstate Rule ("CAIR") and the Clean Air Mercury Rule ("CAMR") were both vacated by the Court of Appeals for the D.C. Circuit in 2008. How does this affect your assumptions?

A37. CAIR had regulated the emissions of SO_2 and NOx through a cap and trade program that was to begin 2009. Absent CAIR, there will need to be some form of replacement legislation that creates rules for achieving the emissions reductions set forth in the 1990 National Ambient Air Quality Standards. However, the details of any such rules are not known at this time. I have therefore assumed that the vintage emissions allowance requirements mandated by CAIR provide the most reasonable forecast of those requirements that may be included in any replacement legislation. I have also therefore retained Ventyx's emissions allowance cost assumptions, which were made before CAIR was vacated.

CAMR had regulated mercury emissions through a cap-and-trade program that was to begin in 2010. Absent CAMR, it is likely that the EPA will mandate plant-level standards for mercury emissions in the future. However, no specific guidance has been offered as to the likelihood of implementing these standards or the level of controls that they may require. Ventyx has assumed no cost in the modeling specific to mercury reductions. I find this assumption to be reasonable because 1) the standards for mercury emissions in the future are not known at this time; and 2) there is already a co-benefit of mercury emissions reduction through the Company's existing and forecast SO_2 and NOx controls.

Q38. What did you assume with respect to the potential for a tax or cap-and-trade system with respect to carbon dioxide emissions?

A38. The Reference Case assumes that a Federal cap and trade program is enacted and becomes binding on the NIPSCO Generation Assets in 2012, with prices taken from the Ventyx forecast, beginning at $5.38/ton in nominal terms and escalating to $23.39/ton in 2025. I find this forecast to be at the low end of the reasonable range of possible outcomes with respect to CO_2 regulation. I assumed that the cost of CO_2 allowances was incurred on a pay-as-you-go basis, with no banking. While some form of Federal regulation of greenhouse gas has become a near certainty in the next Administration, both the timing and content of any such legislation is difficult to predict.

Q39. How were surplus emissions allowances treated in the analysis?

A39. For the purposes of my analysis, I have not assigned any value to remaining emissions allowances that may remain at the end of the useful lives of the plants.

Q40. How were the emissions rates, allowances, and prices established?

A40. The emissions rates were provided by the Company. The allowances were based on EPA's allowance allocations, and were also provided by the Company. The emissions allowance price forecasts used in my analysis are the same as those used in the Ventyx zonal Reference Case analysis.

Q41. Did the analysis include any consideration for future planned investments in emissions reduction technology?

A41. Yes. The Company provided a projection of all forecast capital expenditures for the period from 2008 through 2012. The Company also provided a schedule of specific emissions controls installations that have been planned through 2020.

Q42. Please explain how these investments were included in the analysis.

A42. In the year following any substantial investment in emissions reduction technology, I ascertained that the associated emissions rates for the specific unit were reduced and that fixed operating and maintenance expenses were increased in order to reflect the effect on these items that would be expected once the technology was installed. Overall, however, installing emissions controls technologies has the effect of lowering the costs associated with purchasing emissions allowances for the remainder of the study period.

Q43. How was depreciation factored into the analysis?

A43. Depreciation is a permissible deduction for tax purposes using IRS-prescribed accelerated tax depreciation rates. As noted earlier in my testimony, I have assumed that a buyer has acquired the NIPSCO Generation Assets at the valuation date, thereby increasing the tax basis of those assets to the level of the purchase price. I have, therefore, assumed that the buyer may then depreciate the full value of the transaction for tax purposes. This assumption creates an iterative step in the valuation process, as the value of the tax depreciation is added to the asset value, and this process is repeated until negligible value is added by the next iteration. In addition, projected capital improvements in each year were depreciated going forward in the DCF model. For both purposes, I have assumed a 20-year depreciation rate under the Internal Revenue Service system known as the Modified Accelerated Cost Recovery System ("MACRS"). It is important to note that in the DCF analysis, depreciation is deducted as an expense in order to calculate income taxes, but is added back for cash flow purposes because it is a non-cash item. Therefore, the amount of depreciation in any year affects operating cash flows solely through its effect on income taxes.

Q44. Why did you use tax depreciation rather than book depreciation in the DCF model?

A44. The purpose of the DCF analysis is to calculate the future stream of cash generated by each facility. The depreciation amount that determines the cash needed to pay income taxes is the depreciation deductible on the income tax return. Book depreciation expense may be quite different from tax depreciation expense due to the differences in the accounting methods that are used for these purposes.

Q45. What assumptions did you use regarding tax rates?

A45. Income tax rates were based on existing Federal and State of Indiana corporate income tax rates. Property taxes were calculated using 2007 payments as provided by the Company, escalated at the assumed inflation rate.

Q46. Does the analysis consider future capital additions?

A46. Yes. The Company provided estimated capital budgets for the years 2008 through 2012, which were included in the analysis. I reviewed the capital budgets to determine those expenditures that would likely be recurring in order to derive an annual capital budget for the remainder of the useful lives of each of the NIPSCO Generation Assets. I then added the capital expenditures for associated specific emissions control projects expected to take place after 2012 as provided by the Company. I also estimated a maintenance level of post-2012 capital expenditures by calculating the average capital expenditures in the pre-2012 period before environmental controls installations and other non-recurring expenditures.

Q47. Does your consideration of future capital additions mean that you included property that is not currently in service in your fair value estimate?

A47. No, quite the contrary. I deducted future capital expenditures at each facility because these expenditures reduce cash flow. As I indicated previously, capital expenditures are deducted from net operating income, while depreciation, including new planned expenditures, is added back to after-tax income. The result is net operating cash flow.

Q48. From your inspection and investigation of the NIPSCO Generation Assets, were there any specific observations about the operation or condition of the generation assets that would affect the value of the assets in the DCF analysis?

A48. Yes, I reviewed several recent outages of the various units and confirmed that they were satisfactorily resolved.

Q49. The Bailly plant uses a flue gas de-sulfurization ("FGD") facility that is under a lease agreement with Pure Air. How was this lease incorporated into your analysis?

A49. I incorporated the lease payment to Pure Air in my financial model through the projected life of the facility. The lease contract expires in 2012. The annual lease payment includes both a capital portion, which includes the capital costs of the FGD facility, and an operating portion, which includes all operations and maintenance as well as materials costs. While contract renewal is subject to negotiation, NIPSCO will likely be responsible for only the operating portion of the lease in order to maintain service in the post-2012 period. I therefore have modeled the lease payments according to this schedule.

Q50. Having derived all of the projected cash flows for the NIPSCO Generation Assets, how did you arrive at a value for these assets?

A50. I used a discount rate to express these cash flows in the value of present-day dollars.

Q51. How did you develop the discount rate for your DCF analysis?

A51. As I noted previously, the DCF analysis produces a value for an asset in current dollars based on that asset's future cash flow stream. In order to convert those future cash flows into current dollars, the cash flows must be discounted using a rate that is appropriate for the asset, *i.e.*, a discount rate. The discount rate represents the rate of return an investor would seek for the asset being valued, and should therefore reflect the risk of the projected cash flows from the asset. For this purpose, I assumed that a purchaser of the NIPSCO Generation Assets would receive a long-term contract to sell the power back to

NIPSCO at market-based rates. This assumption is reasonable based upon the Company's 2007 IRP, which reflects an ongoing need for the generating capacity from these assets.

Q52. How did you calculate the discount rate for the DCF analysis?

A52. My approach was to derive a discount rate that is equivalent to the cost of capital of a non-rate-regulated merchant generator selling power at market-based prices. First, for my analysis, I used a pre-tax 7.8% cost of debt based on three recent bank debt financings related to the acquisition of generation facilities in the US, and converted the interest rates in these financings to a ten-year fixed rate through a swap of the London Interbank Offered Rate ("LIBOR"). This 7.8% rate reflects a 4.7% LIBOR swap rate and a 3.1% spread. Since interest on debt is tax deductible, I then converted the pre-tax cost of debt to an after-tax figure based on a 35% Federal tax rate and an Indiana state income tax rate of 8.5%.

Next, I calculated a 13.4% cost of common equity using the Capital Asset Pricing Model ("CAPM"), a well recognized and commonly-used methodology for this purpose. My CAPM model refers to the relative market risk of five companies that are engaged primarily in the independent electric generation business.

Lastly, I used a capitalization ratio of 50% debt and 50% equity, which is representative of the debt-to-equity ratios currently used in the financing of unregulated generation assets. Through the above steps, I arrive at a 9.0% weighted average cost of capital, which I have used to discount future cash flows from the NIPSCO Generation Assets.

Q53. Why did you not use a discount rate for NIPSCO as a whole as your discount rate for this purpose?

A53. The risk that the future cash flows from the NIPSCO Generation Assets will materialize as forecast is closely related to the risk of owning generating assets. In contrast, the discount rate for NIPSCO as a whole would also reflect a substantial component related to the risk of owning regulated distribution and transmission assets. Given the relatively high risk of market price variation in the restructured generation markets, along with higher rates of technological failure for generating assets relative to distribution and transmission assets, the discount rate for the NIPSCO Generating Assets alone is higher than the discount rate for NIPSCO as a whole.

V. <u>SUMMARY AND CONCLUSION</u>

Q54. What were the results of the DCF Approach?

A54. A summary of the results of the DCF Approach for NIPSCO's generation assets is provided in <u>Petitioner's Exhibit JJR-4</u>. As shown in this Exhibit, the DCF Approach resulted in an overall value for NIPSCO's generation assets of $2.270 billion or an average of $819/kW. This is a reasonable valuation using the DCF Approach.

Q55. Does this conclude your prepared Direct Testimony?

A55. Yes, it does.

VERIFICATION

I, John J. Reed, Chairman and CEO, Concentric Energy Advisors, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

John J. Reed

Date: August 19, 2008

INDS01 DWM 1051910

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 30 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

Litigation Support and Expert Testimony

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)
Chairman, Presidnet, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
District Of Columbia PSC				
Potomac Electric Power Company	3/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Direct)
Potomac Electric Power Company	5/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Supplemental Direct)
Potomac Electric Power Company	7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Rebuttal)
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92	Lakehead Pipe Line Co. L.P.	IS92-27-000	Rate Case Analysis Cost of Service
Colonial Gas, Providence Gas	7/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	8/93	Algonquin Gas Transmission	RP93-14 – Rebuttal	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates
Tennessee GSR Group	1/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
Pacific Gas Transmission	2/95	Pacific Gas Transmission	RP94-149-000	Rate Design
Tennessee GSR Customer Group	3/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
ProGas and Texas Eastern	1/96	Tennessee Gas Pipeline Company	RP93-151	Declaration
PG&E and SoCal Gas	96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 07____-EI	Need for new nuclear plant
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Cause No. 41746	Standby Charge

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Docket No. 99-0207	Direct Testimony, Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Public Benefits
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Public Benefits
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Public Benefits
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Public Benefits
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Public Benefits
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection (Direct)
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
Coalition of Non-Utility Generators		Cambridge Electric Light Co. & Commonwealth Electric Co.	DPU 91-234 EFSC 91-4	Review Integrated Resource Management Filing
The Berkshire Gas Company Essex County Gas Company Fitchburg Gas and Elec. Light Co.	5/92	The Berkshire Gas Company Essex County Gas Company Fitchburg Gas & Elec. Light Co.	DPU #92-154	Gas Purchase Contract Approval
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Company	11/93	The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Co.	DPU #93-187	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs – Direct
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Regulatory Issues

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	Industry Norms and Financial Impacts
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH3-93	Cost of Capital
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Segmented Service
Brunswick Pipeline	9/06	Brunswick Pipeline	GH-1-2006	Market Study

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
TransCanada Pipelines Ltd.	3/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Atlantic Wallboard/JD Irving Co.	MCTN #298600	Rate Setting for EGNB
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
New Mexico Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Evaluate their use of storage
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage
Pennsylvania Public Utility Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
ATOC	4/95	Equitrans	Docket No. R-00943272	Tariff Changes
ATOC	3/96	Equitrans	Docket No. P-00940886	Rate Service - Direct
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Rate Filing Package; Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Texas Railroad Commission				
Southern Union Gas	5/85	Southern Union Gas Company	G.U.D. 1891	Cost of Service
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	benchmarking
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Tariff Filing
Green Mountain Power	7/98	Green Mountain Power	Docket No. 6107	Direct Testimony
Green Mountain Power	9/00	Green Mountain Power	Docket No. 6107	Rebuttal Testimony
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern	Arbitration Panel	Gas Contract Arbitration
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service
State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
Consolidated Edison of New York	08/07	Consolidated Edison of New York, Inc. and subsidiaries v. United States	No. 06-305T	Leasing Litigation
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Expert Report, Shortnose Sturgeon Case
Central Hudson Gas & Electric	8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Revised Expert Report, Shortnose Sturgeon Case
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
District of Columbia Court City Council				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring

Northern Indiana Public Service Company
Generation Assets

A	B	C	D	E	F	G	H	I	J
Line No.	**Unit Name**	**Unit Number**	**Location**	**Capacity (MW)**	**Fuel Type**	**Year In Service**	**First Year Unavailable**	**DCF Value ($Millions)**	**DCF Value ($/kW)**
1	Bailly	7	Chesterton	160	Coal	1962	2023		
2	Bailly	8	Chesterton	320	Coal	1968	2029		
3	Bailly	10	Chesterton	31	Natural Gas	1968	2019		
4	Total Bailly			511				$185.4	$362.8
5	Michigan City	12	Michigan City	469	Coal	1974	2035	$315.7	$673.2
6	Schahfer	14	Wheatfield	431	Coal	1976	2037		
7	Schahfer	15	Wheatfield	472	Coal	1979	2040		
8	Schahfer	16A	Wheatfield	78	Natural Gas	1979	2020		
9	Schahfer	16B	Wheatfield	77	Natural Gas	1979	2020		
10	Schahfer	17	Wheatfield	361	Coal	1983	2044		
11	Schahfer	18	Wheatfield	361	Coal	1986	2047		
12	Total Schahfer			1,780				$1,757.8	$987.6
13	Norway		Monticello	4	Water	1923	Perpetual	$1.8	$451.8
14	Oakdale		Monticello	6	Water	1925	Perpetual	$9.7	$1,614.3
	Grand Total			2,770				$2,270.4	$819.6

Petitioner's Exhibit VFR-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

VICTOR F. RANALLETTA

ASSOCIATE ENGINEER AND
MANAGER – ENERGY, CHICAGO REGIONAL OFFICE
BURNS & MCDONNELL ENGINEERING CO., INC.

SPONSORING PETITIONER'S EXHIBITS VFR-2 THROUGH VFR-7

VERIFIED DIRECT TESTIMONY OF VICTOR F. RANALLETTA

Q1. Please state your name and business address.

A1. My name is Victor F. Ranalletta. My business address is 1431 Opus Place, Suite 400, Downers Grove, IL 60515.

Q2. By whom are you employed and in what capacity?

A2. I am an Associate Engineer and the Manager of the Energy Division in the Chicago Regional Office of Burns & McDonnell Engineering Co., Inc. ("BMcD").

Q3. Please describe the business of BMcD.

A3. BMcD is a consulting engineering firm working with many industries, including electric utilities. BMcD has provided consulting engineering services to the utility industry for over 100 years. BMcD serves electric utility, commercial, institutional, industrial and government clients, conducting various power-related economic, cost and design studies. BMcD provides facility design services for steam and electric generation, including assisting clients in the start-up and performance testing of new and reconditioned plants, performing plant performance and operations assessments, and training clients' operations and maintenance ("O&M") personnel.

BMcD specialties address critical issues and aspects of electric system and power plant planning, design, operations, and upgrade. BMcD in-house economic advisors run pro-forma analyses and economic justification studies. BMcD is also involved in air pollution control study, design, and testing of steam and electric generating units, as well as industrial processes. A testing group provides emissions testing and air monitoring services for permits, compliance certification and diagnostics. BMcD staff includes nationally recognized specialists in siting, permitting, particulates removal equipment, and flue gas desulfurization systems.

Q4. What is your educational background?

A4. I received a Bachelor of Science Degree in Mechanical Engineering in 1976 from the University of Illinois and a Master of Science Degree in Mechanical Engineering in 1980 from the University of Illinois. My professional career started in 1978 with Brown & Root upon the completion of my Master's work.

Q5. Please describe your professional experience.

A5. I have 30 years of power plant, refinery, chemical plant, and industrial plant design experience with prior work experience at Brown & Root, Fluor Daniel, and Indeck Energy Services. My position at Indeck prior to joining BMcD was Vice President, Project Management & Construction, reporting to the President and Chief Operating Officer. In that position, I managed all permitting, engineering, project management, and construction activities. I joined BMcD in 2006 as a Manager of the Energy Division in the Chicago Regional Office, which is my current position. I am a licensed professional engineer in the states of Illinois, Indiana and Kansas.

Q6. What experience have you had in the design and construction of generating stations?

A6. My experience in the design and construction of generating stations includes both new power plants and the retrofitting and modification of existing power plants. My design and construction experience with respect to new plants includes: Nevada Power Company, Reid Gardner Station – Unit 3, 300 MW coal fired power plant; Louisville Gas & Electric Company, Trimble County Station – Unit 1, 550 MW coal fired power plant; Public Service Company of New Mexico (now PNM), San Juan Generating Station – Unit 3, 550 MW coal fired power plant; Enfield Energy Centre (Enfield, UK), 400 MW combine cycle gas turbine generating station; Rockford Energy Center, Phase I (330 MW) & II (165 MW) simple cycle gas turbine generating station; Escuintla Energy Center (Escuintla, Guatemala), 40 MW heavy fuel oil fired generating station; Corinth Energy Center (Corinth, NY), 125 MW combine cycle gas turbine generating station; and Goodman Energy Center, Midwest Energy, 75 MW natural gas fired generating station. My retrofit design and construction experience includes coal fired plants owned by: We Energies; Midwest Generation EME, LLC (formerly ComEd); Hoosier Energy Rural Electric Cooperative, Inc.; Southern Indiana Gas & Electric Company (A.B. Brown Station); Louisville Gas & Electric Company; and Northern Indiana Public Service Company ("NIPSCO").

Q7. What are your responsibilities as Manager – Energy, Chicago Regional Office?

A7. My responsibilities include, but are not limited to, management of a multi-discipline engineering and design group specializing in new and retrofit projects in thermal energy and power generation plants utilizing coal, natural gas, oil, and renewable energy fuels.

Q8. What is the purpose of your testimony?

A8. My testimony in this proceeding will address the results of studies performed by BMcD estimating the cost of demolishing certain NIPSCO electric power generating stations and remediating the sites (collectively referred to as "demolition cost"). BMcD was engaged by NIPSCO to perform these studies and to prepare written reports on our results.

Q9. What was your involvement in performing the studies?

A9. I supervised and directed the studies. The BMcD team also included a development engineer, a structural engineer, an electrical engineer, an environmental geologist, two environmental engineers and a mechanical engineer.

Q10. Have you personally inspected each of the generating stations for which BMcD performed demolition cost studies?

A10. Yes.

Q11. Did you rely on other information besides the site visits for purposes of your opinions?

A11. Yes. NIPSCO has provided certain additional background information, including site and equipment drawings, information concerning asbestos and other potential contamination, and general discussions of the plants during site visits. I consider the information to be reliable for purposes of my work and of a type that is generally relied upon by experts like me for purposes of estimating demolition costs.

Q12. Why is it necessary to demolish a generating station at the end of its useful life?

A12. In order to reuse the land, the structures need to be removed. Reuse is a significant issue for generating station sites because the number of sites suitable for such a use is limited. Therefore, a retired station will likely be demolished to allow construction of a new generating station at that same site. Safety concerns also support removal. Unused structures will deteriorate if not maintained and require security protections. Some of the structures, stacks for example, could collapse causing damage. Asbestos, which is believed to be a health hazard, also requires removal and disposal.

Q13. Please describe the documents that have been identified as Petitioner's Exhibits VFR-2 through VFR-7.

A13. These documents are written reports on BMcD's site-specific demolition cost studies of NIPSCO's fossil-fuel fired generating stations. In these studies, BMcD estimated the cost of demolishing the power block equipment and facilities and site facilities and remediating the site. BMcD prepared separate reports for the Schahfer Generating Station (Petitioner's Exhibit VFR-2); the Bailly Generating Station (Petitioner's Exhibit VFR-3); the Mitchell Generating Station (Petitioner's Exhibit VFR-4); the Sugar Creek Generating Station (Petitioner's Exhibit VFR-5); Michigan City Station Units 2 & 3 (Petitioner's Exhibit VFR-6); and Michigan City Station Units 2 & 3 Building, Unit 12 and Balance of Plant (Petitioner's Exhibit VFR-7). Each report describes the plant, sets forth the general cost assumptions used in the studies, identifies costs not included in the studies, explains how scrap material value was determined and provides detailed cost estimates for demolition and remediation to both industrial condition and greenfield condition. The cost estimates reflect what it would cost today to do the work in 2008 dollars.

Q14. Please explain the differences between the demolition cost estimates of each generating station.

A14. The demolition cost estimates for Schahfer, Bailly, Mitchell and Sugar Creek assumed demolition of the complete station during one continuous demolition and remediation operation. We have prepared two reports on the Michigan City Station to reflect NIPSCO's plan to dismantle Units 2 and 3 prior to Unit 12. The Michigan City Units 2 and 3 demolition cost estimate shown in Petitioner's Exhibit VFR-6 is limited to the equipment, systems, and structures directly associated with the operation of these units and assumes the building that houses these units will remain in place and Unit 12 will remain in operation. The Michigan City Unit 12 demolition cost estimate shown in Petitioner's Exhibit VFR-7 represents the cost to demolish and remediate the rest of the site assuming that Units 2 and 3 have been previously dismantled. This estimate includes the cost of removing the building that houses Units 2 and 3, the office area, storeroom, maintenance shops and Unit 12 supporting utilities.

Q15. Please briefly describe how BMcD performed its studies of the cost of demolishing NIPSCO's generating units and remediating the sites to industrial condition?

A15. BMcD first determined the quantities of concrete, structural steel, equipment, electric cable and raceway, conveyors, tanks, and piping that would need to be removed. BMcD derived these quantities from plant site layout drawings, general arrangement drawings, building and structural design drawings, selected mechanical design drawings, and BMcD site walk downs and verification at each station. BMcD based the industrial demolition cost estimates on demolishing each plant down to the surrounding grade elevation. This estimate assumed all equipment and material located above and below grade will be dismantled and either sent to a landfill or sold as salvage in the case of steel and copper. The estimate also assumes all below grade foundations will remain and the below grade excavated areas will be used for landfill space for the demolished plant concrete. Environmental remediation (asbestos removal, lead paint removal, arsenic removal, mercury removal, closing ash ponds and coal yards, etc.) that is required to support the demolition effort are also included in the demolition cost.

Q16. Please explain the terms "plant site layout drawings" and "general arrangement drawings."

A16. Plant site layout drawings show all improvements made to the site, including building and equipment structures, outdoor storage tanks, plant roads, landfill areas, ash pond areas, coal and gypsum byproduct outdoor storage piles, rail line locations, parking areas, electrical switchyards, overhead high voltage electrical transmission lines and structures, water intake and water outfall structures, pumping stations, and secondary containment structures. Plant site layout drawings typically extend to the property lines of each station. General arrangement drawings are large scale drawings of, in this case, generating stations depicting the major structures and component locations. General arrangement drawings are drawn to a certain scale whereas plant site layout drawings may or may not be drawn to scale. The drawing scale allows one to determine accurately the size of the major structures, plant systems, and plant components to form the basis of the material quantity estimates.

Q17. What do the greenfield condition estimates include?

A17. In addition to the industrial demolition cost estimate, the greenfield demolition cost estimates include, the estimated cost to: demolish all below grade foundations and fill the resulting below grade void with soil; cap and close landfills and remediate ash ponds and coal yard areas in accordance with industry accepted and regulatory practices; haul demolished concrete off site to landfills; and remediate plant areas in and around structures, underground oil and hazardous piping, fire training areas, secondary containment areas, and oil storage areas.

Q18. What are the essential differences between "industrial" and "greenfield" condition?

A18. Industrial condition allows the site to be either re-developed as a new electrical generation power plant or re-developed for other industrial or heavy commercial uses. Greenfield condition allows the site to be re-developed for any use (residential, commercial, industrial, or "green" space). The BMcD cost estimates assume environmental remediation is performed to the extent necessary to restore the site to each such condition.

Q19. How were the environmental remediation costs determined?

A19. Environmental remediation costs were added to each cost estimate but were separately developed from NIPSCO internal environmental cost estimates, quotations from an asbestos remediation contractor familiar with and having done work in these generating stations, and BMcD environmental remediation cost and regulatory experience for plants of this type in the states in which the stations are located. NIPSCO's internal environmental experts reviewed and approved the environmental remediation assumptions.

Q20. Please explain the indirect costs included in the cost estimates.

A20. The indirect costs included in the demolition cost estimates reflect the following five categories: owner's indirect costs; engineering; construction management; performance bond; and contractor's indirects. BMcD calculated owner's indirect costs based on two percent of the direct costs based upon BMcD's experience with projects of similar complexity and upon discussions with NIPSCO personnel. This amount is intended to cover NIPSCO's internal costs associated with the dismantling of the generating stations, such as obtaining permits, construction services such as water and electricity, security labor and facilities, site vehicles, procurement services, legal services, and environmental monitoring. The engineering cost represents the cost to retain an engineer contracted by NIPSCO to develop demolition work packages for multiple subcontractors, and providing mechanical, electrical, and structural oversight during the demolition phases, particularly complex demolition, such as the stacks at the various stations, and engineering assistance for the modifications of the switch yard controls where that is necessary.

The construction management cost represents the cost of having three NIPSCO plant employees scheduling, monitoring and supervising the contractors who will be doing the actual demolition work. These employees would be located on the particular site for the duration of the demolition work (contractor mobilization first, then the remediation phase, then the non-hazardous demolition phase, and finally the demobilization and site closure phase). The construction management costs include the costs to support these individuals on site, including salaries, overhead and payroll taxes (the latter internal costs were provided by NIPSCO), construction trailer rental, drinking water, weekly janitorial service, sanitary facilities and office supplies. Vehicle costs for these employees, electrical service, and overall site security costs are included in the owner's indirect costs. BMcD calculated the performance bond costs based on two percent of the costs associated with the value of the demolition contractor(s) contract. This bond percentage is based on the cost for a contractor with an excellent OSHA safety record and a good performance rating to obtain a performance bond from a bond surety company. The performance bond is essentially an insurance policy that can be drawn upon by NIPSCO in the event the contractor is unable to perform the work due to certain situations, *i.e.*, contractor bankruptcy.

Contractor indirect costs in each estimate represents the demolition contractor's jobsite and home office clerical cost, other home office costs including estimating, purchasing, and project management, the cost of small tools and consumables needed to do the work, and the cost of jobsite supervision above the level of foreman (superintendent, site manager, etc.).

Q21. Did BMcD apply a contingency factor in its analysis?

A21. Yes. Cost contingency is included in the cost estimate to cover expenses that are unknown at the time the estimate is prepared, but are expected to be expended on the project. When preparing a cost estimate, there is always some uncertainty as to the precision of the quantities in the estimate, how work will be performed and what work conditions will be like when the project is executed. These uncertainties will impact the actual costs of the project relative to the estimated cost. The estimator is aware of these unknowns when preparing the cost estimate, and based on past experience, prepares an estimate of these probable costs. The estimated cost of these unknowns is referred to as cost contingency.

Q22. What contingency factor was included in the demolition cost estimates?

A22. Based on BMcD's experience with preparing cost estimates related to power generating facilities and dismantlement of those facilities, along with BMcD's experience with actual costs relative to estimated costs, BMcD applied a cost contingency of 20% to the demolition cost estimates. This is a reasonable contingency percentage to use in estimating the demolition costs of NIPSCO's generating stations.

Q23. What positive salvage did BMcD reflect in the demolition cost estimates?

A23. Materials such as steel and copper have a positive scrap value. BMcD determined the average market value based on salvage cost surveys and verbal quotes from scrap dealers and brokers for the materials in the reports. BMcD also estimated the amounts of recoverable steel and copper in each of the stations.

Q24. What is the total estimated net cost to demolish NIPSCO's generating stations and remediate the sites to industrial and greenfield condition?

A24. The total net cost estimate for each station, net of positive salvage, is as follows:

Station	Industrial Condition	Greenfield Condition
Schahfer	$129,806,000	$202,779,000
Bailly	29,379,000	64,211,000
Mitchell	61,596,000	84,248,000
Sugar Creek	2,175,000	5,243,000
Michigan City – Units 2 and 3	18,900,000	Not Applicable
Michigan City – Units 2 & 3 Building, Unit 12, and Balance of Plant	34,509,000	64,591,000

Q25. Did BMcD apply any escalation factor to the demolition cost estimates in the reports?

A25. No, BMcD did not. All of the estimates are in 2008 dollars.

Q26. Please address the reasonableness of the demolition cost estimates contained in <u>Petitioner's Exhibits VFR-2 through VFR-7</u>?

A26. I participated in all site walk downs of each station for the demolition estimates. I was on the BMcD due diligence team for the NIPSCO acquisition of Sugar Creek. I have personally managed other design projects in the Michigan City, Bailly, and Schahfer stations, so I am familiar with the details of each station beyond the walk downs I participated in for the demolition studies. BMcD carefully prepared the estimates using standard and accepted estimating techniques and the best information available. Additionally, these estimates are consistent with other available data and industry experience. The assumptions listed in each report are reasonable and the estimates are accurate within the estimating accuracy based on the assumptions made and the aforementioned cost contingency allowance.

Q27. Does this conclude your prepared direct testimony?

A27. Yes, it does.

VERIFICATION

I, Victor F. Ranalletta, Associate Engineer and Manager – Energy Chicago Regional Office for Burns & McDonnell Engineering Co., Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Victor F. Ranalletta

Victor F. Ranalletta

Date: August 18, 2008

INDS01 DWM 1040973 .DOC

Petitioner's Exhibit VFR-2
Northern Indiana Public Service Company
Cause No. 43526

Report on the

Asset Demolition Study
Schahfer Generating Station

for

Northern Indiana Public Service Company
Valparaiso, Indiana

Project Number 48492

June 20, 2008

Burns & McDonnell
SINCE 1898

Petitioner's Exhibit VFR-2
Northern Indiana Public Service Company
Cause No. 43526

Asset Demolition Study
Schahfer Generating Station

prepared for

Northern Indiana Public Service Company
Valparaiso, Indiana

June 20, 2008

Project No. 48492

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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Asset Demolition Study
Schahfer Generating Station

Project 48492

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APPENDIX A – DEMOLITION COST BREAKDOWNS

* * * * *

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A.1 Demolition Cost Breakdown: Option 1 – Full Demolition, Industrial Site
A.2 Demolition Cost Breakdown: Option 2 – Full Demolition, Greenfield Site

* * * * *

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Burns & McDonnell (B&McD) was retained by Northern Indiana Public Service Company to conduct an Asset Demolition Study of the Schahfer Generating Station (Plant). The purpose of the Asset Demolition Study was to review the Plant facilities and to provide an estimate to NIPSCO regarding the total cost of complete demolition of the Units. The following report documents our efforts on this study.

The Schahfer Generating Station is a coal-fired Plant consisting of four coal-fired boilers and steam turbine/generators. Two of the coal-fired units are rated at 361 MW (Units 17 & 18), one is rated at 431 MW (Unit 14), and the fourth is rated at 472 MW (Unit 15). In addition to the coal-fired boilers, there are two natural gas-fired combustion turbine generators at the site, each rated at approximately 78 MW (Units 16A & 16B).

1.2 RESULTS

When NIPSCO determines that the Plant facilities should be demolished, the above grade equipment and steel structures are assumed to have significant scrap value to a salvage contractor. The scrap value of these items will be used as a credit against the demolition costs. However, NIPSCO will incur costs in the restoration of the site following the removal of salvageable equipment.

The asset demolition costs were developed for two scenarios. The first scenario was based on leaving the site in an industrial condition, with below grade foundations and structures remaining on-site, and an on-site inert waste landfill. The second scenario was based on returning the site to a greenfield condition with no structures remaining, compatible with the surrounding land, similar to the conditions that existed before development of the Plant.

Based on the results of the Asset Demolition Study conducted for the Schahfer Generating Station, the estimated demolition costs in current dollars (2008 $) are summarized in Table 1.1 below.

Table 1.1

Demolition Cost Estimate Summary

Option	Total Cost	Project Duration
Full Demolition, Industrial Site	$ 129,806,000	40 Months
Full Demolition, Greenfield Site	$ 202,779,000	48 Months

* * * * *

2.0 PLANT SITE

2.1 SITE VISIT

Representatives from B&McD visited the Plant on April 8, 2008. The purpose of the site visit was to gather information to conduct the Asset Demolition Study, interview the Plant management and operations staff, and to conduct an on-site review of the Plant facilities. The following B&McD representatives comprised the Asset Demolition Study team:

- Mr. Vic Ranalletta, Engineering Manager, Mechanical Engineer
- Mr. Lawrence Fieber, Environmental Geologist
- Mr. Jeff Grubich, Environmental Engineer
- Mr. Mark Sarceda, Mechanical Engineer

2.2 PLANT DESCRIPTION

The Schahfer Generating Station is a coal-fired Plant consisting of four coal-fired boilers and steam turbine/generators. Two of the coal-fired units are rated at 361 MW (Units 17 & 18), one is rated at 431 MW (Unit 14), and the fourth is rated at 472 MW (Unit 15). In addition to the coal-fired boilers, there are two natural gas-fired combustion turbine generators at the site, each rated at approximately 78 MW (Units 16A & 16B).

The coal-fired boilers and steam turbine/generators are housed in a metal-sided boiler and turbine building. The combustion turbine/generators are housed in weatherproof equipment enclosures. Each Unit has a concrete stack with a flue liner and emission monitoring systems.

Unit 14 has a flue gas electrostatic precipitator (ESP) and selective catalytic reduction (SCR) system. Units 15, 17, and 18 have an ESP. Units 17 & 18 each have a flue gas sulfur dioxide removal scrubber system to accommodate the high sulfur coal burned in these Units. The scrubber system includes the following: scrubber modules; slurry pump building; concrete storage silos for powdered limestone; hydrated lime powder storage tank; slurry pumps and tanks; lime truck unloading area; a gypsum belt conveyor which conveys gypsum off site to a wallboard plant owned and operated by a private commercial concern. The NIPSCO site includes open pile storage for gypsum to satisfy the contractual supply of gypsum to the wallboard plant during unit outages..

Stand-alone, concrete mechanical draft cooling towers provide the thermal cycle cooling for each unit. Each Unit has a dedicated cooling tower and the associated circulating water pumps and electrical switchgear. Underground circulating water pipes extend between the towers and the Units.

Several levels of structure exist below the turbine floor where ancillary equipment for the Units resides. The lowest level for each Unit is at the natural grade elevation. The structure below the operating floors houses the surface condensers, condensate pumps, and other ancillary equipment and systems for the Units, auxiliary transformers, motor control centers (MCCs) and switchgear.

Coal is delivered to the Plant by rail cars. Since the Plant burns both low and high sulfur coal, a separate pile is provided for each coal. Units 14 & 15 utilize open coal piles. Units 17 & 18 utilize open coal piles and an "A" frame metal roofed chapel for reclaim storage. Each separate coal handling system includes the following: rotary coal unloading; thaw shed; coal storage; stack-out and reclaim system; sampling house; and crusher house. Coal is conveyed from the unloader to a transfer house where the coal either is directed to a radial stacker out to an open coal pile and/or chapel, or to the sampling house and then to the coal crusher house. A series of conveyors and transfer houses move crushed coal to the tripper conveyors located above the coal bunkers located between the boiler and turbine rooms. Tractor garages and tractor / rail car maintenance buildings are located within each coal yard.

The Plant has a rail car bulk lime unloading system that is in place but is no longer used for unloading.

Makeup water for cooling and process water needs for all Units is supplied from a tributary of the Kankakee River. An intake and pump house is located north of the Plant on NIPSCO property. Makeup water is conveyed in underground piping from the pump house to the Units. Potable water is supplied from a well field located north of the Plant on NIPSCO property. Potable water is conveyed in underground piping from the individual well pump installations to the Units.

The Plant includes on-site potable water tanks, demineralized and condensate water tanks, abandoned aboveground fuel oil storage tanks (one used for parts storage), ash settling basins, landfill, and ash ponds with recycle water pump houses.

* * * * *

3.0 SITE DEMOLITION

Two separate cost estimates were prepared for different site demolition scenarios. The first option evaluated included removal of all above grade equipment, piping, and wiring relating at the site, including the buildings, but leaving the foundations and below grade piping and wiring in place, to return the area to an industrial site. The second scenario included removal of all above grade equipment, piping, wiring at the site, including the buildings, foundations and below grade piping and wiring, to return the area to a greenfield site. A breakdown of each of the demolition cost estimates is provided in Appendix A.

3.1 OPTION 1 – FULL DEMOLITION, INDUSTRIAL SITE

This Option includes removing all equipment at the site, as well as the building structure, but leaving the foundations and below grade piping and wiring in place. All asbestos will be removed, as well as any PCBs, and mercury. The equipment will then be removed and the building demolished. The foundations will remain in place, and the subgrade structure will be used as a repository for inert demolition debris. Underground piping will be capped and abandoned in place and underground wiring and busduct will be abandoned in place.

The estimated cost for this demolition option is $129,806,000.

3.1.1 General Cost Assumptions and Clarifications

The following items are included in the cost estimate:

- All estimates are budgetary in nature and do not reflect guaranteed costs.
- All estimates are based on union labor.
- Sufficient area to receive, assemble and temporarily store equipment and materials is available.
- All cost estimates are in current 2008 dollars.
- The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition, therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap at the time of site demolition.
- All oils must be confirmed to be polychlorinated biphenyl (PCB) free. If any PCBs are discovered, they will be disposed of properly. Concrete pads and/or flooring surrounding internal transformers will be removed and properly disposed.

- Impacted soils surrounding exterior transformers will be removed to approximately 3 feet below ground surface and disposed of properly.
- All asbestos-based materials will be removed and disposed of in accordance with EPA and OSHA regulations. Transite wall paneling, floor tile, ceiling tile and all other asbestos containing materials will be removed from all structures and disposed of off-site in accordance with state regulations. The costs include scaffolding necessary to complete the work.
- Batteries, including lead and nickel cadmium batteries will be removed and recycled or disposed of properly. Concrete flooring in battery rooms will be removed and properly disposed.
- Mercury-filled equipment and instruments will be removed and disposed of or recycled. Other materials including flooring will be separated from the demolition debris and disposed of properly. Mercury-impacted electrical equipment in control rooms will be disposed of properly.
- Freon will be removed and disposed of properly.
- All environmental related costs were obtained through data and information collected during site visits and discussions with NIPSCO operations and NIPSCO environmental employees. NIPSCO environmental costs were used for the historic contamination associated with Solid Waste Management Units (SWMUs) and for the landfill closure at Schahfer. These costs were reviewed and professional judgment was made to ensure that the costs were reasonable and appropriate.
- All waste products such as solvents and oils located in maintenance facilities will be removed and properly disposed. In addition, concrete flooring and impacted soils will be removed and properly disposed.
- OSHA HAZWOPER trained construction workers will be used to remove arsenic-coated steel in boilers.
- OSHA HAZWOPER trained construction workers will be used to remove lead-based paint coated steel.
- Gauges containing low-level radioactive materials will be removed and disposed of properly.
- Above grade piping and all tanks will be removed and disposed of properly. Petroleum-impacted soils associated with oil piping and both aboveground and underground storage tanks will be removed and disposed of properly.
- All above grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished to grade.
- All above grade plant structures will be demolished to grade. All other building and structure materials such as elevated concrete floors, concrete pedestals above grade, fire walls, masonry, doors,

windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc. will be disposed of in the on-site inert waste landfill where possible.

- An on-site inert waste landfill will be utilized for demolition debris consisting of brick, block, concrete and any other materials that fall under the inert waste category. The on-site ponds and ash landfill will serve as the primary location for the inert waste landfill.
- Onsite solid waste management units will be properly remediated under RCRA as part of this option.
- All coal in storage will be burned prior to decommissioning.
- The coal handling and storage area will be capped with 1 foot of soil material and seeded. Sufficient on-site material for capping is not available at the Schahfer facility for both the ash ponds and the coal handling and storage area, therefore, off-site material will be used for capping the coal handling and storage area.
- Water will be drained from the coal pile runoff pond located east of the coal yard. Sludge and contaminated soil will be stabilized, excavated, and disposed of at an off-site landfill as a hazardous material.
- The coal storage yard will be covered with topsoil, graded for drainage and seeded. Vegetation will be re-established in the coal pile runoff pond, and it will function as a stormwater runoff surge pond for the coal yard area.
- Openings in the coal unloading and reclaim hopper structures will be sealed with concrete and covered with three feet of fill above existing grade after equipment is removed and drains plugged.
- The above ground conveyors and structures, stacking tubes, transfer houses, conveyor tunnel portals, and crusher house will be demolished. To the extent practical, structural steel and conveyor components will be scrapped. All other building materials, i.e. concrete, brick, etc., will be disposed of in the on-site inert waste landfill where possible.
- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly.
- Ash storage silos/structures, ash piping, pipe racks, and associated equipment will be demolished to grade and scrapped. The exposed foundations will be covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- The onsite fly ash landfill will include the addition of a slurry wall for containment and be capped with a geomembrane liner followed by 3 feet of soil material and seeded. Groundwater monitoring wells will be installed around the landfill.
- All remaining plant structures and yard buildings will be demolished. Building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade,

masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in the on-site inert waste landfill where possible.

- Below grade foundations and ground floor slabs will be left in place and covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- Underground piping systems will be purged of all oils or chemicals other than water, excavated and disposed of properly.
- River intake pumps, motors, screens, electrical equipment, and building will be removed and salvaged or scrapped.
- The river intake structure will be, at a minimum, demolished to grade. The outfall structure will be capped with concrete and covered with materials required to restore the original river bank line. The remaining river intake structure will be filled with materials approved by the US Army Corps of Engineers and covered to restore the original river bank line.
- The potable water well field pumps, motors, screens, electrical equipment, and enclosures will be removed and salvaged or scrapped. All existing wells will be closed in accordance with state requirements.
- All portable tanks will be removed from the site, including any propane tanks, oil storage tanks, chemical totes and waste oil tanks.
- All chemicals will be consumed prior to shut down or disposed of properly, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
- The fire training area will be excavated with structures to an average depth of approximately 1 foot below ground surface and disposed of properly.
- All trash debris and miscellaneous waste will be removed and disposed of properly.
- Water will be drained from all on-site ash and settling ponds. Berm material will be graded into the ponds prior to capping. The ash ponds will be covered with 6 inches of soil followed by a low permeability geomembrane liner overlaid with a final protective vegetative cover of 2 feet of soil, which will be graded for drainage, and seeded. The remaining ponds will be covered with a minimum of 2 feet of soil, graded to drain and seeded. On-site material for capping is available at the Schahfer facility.
- All existing deep wells will be closed in accordance with state requirements.
- Groundwater monitoring wells will be installed for the closed ponds.
- Equipment spare parts will be removed and sold.
- Plant mobile maintenance equipment and shop maintenance equipment will be removed and salvaged.

- Universal wastes present in office areas that require special handling and disposal such as mercury in fluorescent bulbs and thermostats and PCB contaminated ballasts will be segregated and properly disposed.
- Universal wastes present throughout the remaining areas of the plant that require special handling and disposal such as mercury vapor bulbs and ballasts and fluorescent lighting bulbs and ballasts will be segregated and properly disposed.

3.1.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalation
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition.
- Transmission or distribution (non-generation) substation modifications or relocation.

3.2 OPTION 2 – FULL DEMOLITION, GREENFIELD SITE

This option includes returning the plant to a Greenfield site condition. Under this scenario, an on-site inert debris landfill would not be used. This cost estimate would include the additional costs associated with hauling all demolition debris off site and also removing below grade foundations, equipment and structures. All underground piping and busduct would be excavated and removed as well.

The estimated cost for this demolition option is $202,779,000.

3.2.1 General Cost Assumptions and Clarifications

The following items are included in the greenfield cost estimate in addition to or replacement of the assumptions stated for the industrial site closure:

- Impacted soils surrounding exterior transformers will be removed to approximately 10 feet below ground surface and disposed of properly.
- Below grade piping and all tanks will be removed and disposed of properly.

- All below grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished including subsurface structures.
- All above grade plant structures will be demolished including subsurface structures. Building and structure materials such as elevated concrete floors, concrete pedestals above grade, subsurface structures, fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc., will be disposed of in an off-site landfill.
- A total of 1 foot of material in the coal handling and storage areas will be removed and disposed of at an off-site landfill as a hazardous material. One foot of offsite material will be brought to the facility to replace the material removed and revegetated.
- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly. Impacted soil surrounding the rail lines will be excavated to approximately 1 foot below ground surface and properly disposed.
- All remaining plant structures and yard buildings will be demolished. All building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in an off-site landfill.
- Below grade foundations and ground floor slabs will be demolished and the debris disposed of in an off site landfill.
- The entire river intake and outfall structures will be demolished and the debris disposed of in an off site landfill. After removal of the river intake and outfall structures, the areas will be covered with materials required to restore the original river bank line.
- The fire training area will be excavated with structures to an average depth of approximately 3 feet below ground surface and disposed of properly.
- All fixed equipment and below-grade storage vessels will be removed from the site.

3.2.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalation
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition

- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition
- Transmission or distribution (non-generation) substation modifications or relocation.

3.3 BULK SCRAP MATERIAL VALUE

Burns & McDonnell estimated the quantity of some bulk scrap materials that could be used to offset demolition costs. However, due to the complexity of a power plant and the scope of this study, a complete estimate of quantities can not be provided.

The value of these scrap materials was estimated based on recent market prices for bulk scrap. The scrap material prices use for this study were as reported in the March 2008 prices for scrap metal for the Upper Mid-West in the "Demolition Scrap Value and Metal News." The values of scrap quantities utilized in the study are as follows:

- Carbon Steel $230/ton
- Copper $5320/ton

* * * * *

4.0 LIMITATIONS

In preparation of this Asset Demolition Study, B&McD has relied upon information provided by NIPSCO. The information provided by NIPSCO included site and equipment drawings, asbestos remediation estimates prepared by their asbestos contractor Insulco, historic contamination associated with Solid Waste Management Units, the landfill closure costs at Schahfer, and general discussions of the plants during site visits. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of demolition costs are based on Engineer's experience, qualifications and judgment. Weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors at the time of demolition will affect the accuracy of the estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

* * * * *

APPENDIX A – DEMOLITION COST BREAKDOWNS

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TABLE A.1

SCHAHFER GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Plant to Industrial Site

Task	Description	Costs	Credits
1	Environmental Remediation	$56,686,616	$0
2	Building Concrete Removal - Above Grade	$25,410,250	$0
3	Building Structural Steel Removal - Above Grade	$13,303,727	$0
4	Major Equipment Removal		
	a Boilers Demolition	$9,760,934	$0
	b Turbine and Condenser Removal	$1,519,546	$0
	c Chimney Demolition	$826,969	$0
	d Precipitator Demolition	$104,354	$0
	e SCR Demolition	$184,561	$0
	f Cooling Tower Demolition	$1,635,794	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$462,480	$0
	b FGD Demolition	$2,460,378	$0
	c Ash Handling Equipment Demolition	$2,220,821	$0
	d Miscellaneous Mechanical Equipment Demolition	$6,978,395	$0
	e Miscellaneous Piping and Hanger Demolition	$6,418,929	$0
6	Plant Electrical Systems		
	a Transformer Removal	$149,792	$0
	b Electrical Equipment Demolition	$1,095,428	$0
	c Electrical Controls Demolition	$1,083,493	$0
	d Miscellaneous Wiring and Buswork Demolition	$626,696	$0
7	Credit for filling in Turbine, Boiler, Service and Admin Building Foundations		
	a Surplus material for filling ponds, etc...	$0	($9,324,433)

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TABLE A.1

SCHAHFER GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Plant to Industrial Site

Task	Description	Costs	Credits
8	Scrap Value		
a	Steel	$0	($22,662,794)
b	Copper	$0	($108,063)
c	Equipment	$0	($8,445,574)
TOTAL COST (CREDIT)		**$130,929,000**	**($40,541,000)**
PROJECT INDIRECTS			
	Contractor Indirects 5% of Total Cost	$6,546,000	
	Engineering	$655,000	
	Construction Management	$875,000	
	Owner Indirects	$2,619,000	
	Performance Bond	$2,537,000	
CONTINGENCY (20%)		$26,186,000	
TOTAL PROJECT COST (CREDIT)		**$170,347,000**	**($40,541,000)**
TOTAL NET PROJECT COST (CREDIT)		**$129,806,000**	

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TABLE A.2

SCHAHFER GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

Task	Description	Costs	Credits
1	Environmental Remediation	$85,917,437	$0
2	Building Concrete Removal - Above Grade	$25,410,250	$0
3	Building Structural Steel Removal - Above Grade	$13,303,727	$0
4	Major Equipment Removal		
	a Boilers Demolition	$9,760,934	$0
	b Turbine and Condenser Removal	$1,519,546	$0
	c Chimney Demolition	$826,969	$0
	d Precipitator Demolition	$104,354	$0
	e SCR Demolition	$184,561	$0
	f Cooling Tower Demolition	$1,635,794	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$462,480	$0
	b FGD Demolition	$2,460,378	$0
	c Ash Handling Equipment Demolition	$2,220,821	$0
	d Miscellaneous Mechanical Equipment Demolition	$6,978,395	$0
	e Miscellaneous Piping and Hanger Demolition	$6,418,929	$0
6	Plant Electrical Systems		
	a Transformer Removal	$149,792	$0
	b Electrical Equipment Demolition	$1,095,428	$0
	c Electrical Controls Demolition	$1,083,493	$0
	d Miscellaneous Wiring and Buswork Demolition	$626,696	$0
7	Below Grade Demolition		
	a Boiler Building	$3,735,829	$0
	b Turbine Building	$320,716	$0

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TABLE A.2

SCHAHFER GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

Task	Description	Costs	Credits
	c Service Building	$146,093	$0
	d Balance of Plant Buildings	$5,949,095	$0
	e Circulating Water Pipe Demolition	$272,598	$0
	f Below Grade Other Piping Demolition	$214,483	$0
	g Below Grade Busduct Demolition	$6,255,557	$0
8	Scrap Value		
	a Steel	$0	($22,706,413)
	b Copper	$0	($145,884)
	c Equipment	$0	($8,445,574)
9	Site Restoration	$3,203,400	$0
TOTAL COST (CREDIT)		**$180,258,000**	**$ (31,298,000)**
PROJECT INDIRECTS			
	Contractor Indirects 5% of Total Cost	$9,013,000	
	Engineering	$901,000	
	Construction Management	$875,000	
	Owner Indirects	$3,605,000	
	Performance Bond	$3,373,000	
CONTINGENCY (20%)		$36,052,000	
TOTAL PROJECT COST (CREDIT)		**$234,077,000**	**($31,298,000)**
TOTAL NET PROJECT COST (CREDIT)		**$202,779,000**	

Report on the

Asset Demolition Study
Bailly Generating Station

for

Northern Indiana Public Service Company
Valparaiso, Indiana

Project Number 48492

June 20, 2008

Burns & McDonnell
SINCE 1898

Petitioner's Exhibit VFR-3
Northern Indiana Public Service Company
Cause No. 43526

Asset Demolition Study
Bailly Generating Station

prepared for

Northern Indiana Public Service Company
Valparaiso, Indiana

June 20, 2008

Project No. 48492

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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Asset Demolition Study
Bailly Generating Station

Project 48492

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APPENDIX A – DEMOLITION COST BREAKDOWNS

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1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Burns & McDonnell (B&McD) was retained by Northern Indiana Public Service Company to conduct an Asset Demolition Study of the Bailly Generating Station (Plant). The purpose of the Asset Demolition Study was to review the Plant facilities and to provide an estimate to NIPSCO regarding the total cost of complete demolition of the Units. The following report documents our efforts on this study.

The Bailly Generating Station includes coal-fired units consisting of two coal-fired boilers and steam turbine/generators. One of the coal-fired units is rated at 160 MW (Unit 7) and the other is rated at 320 MW (Unit 8). In addition to the coal-fired boilers, there is a 31 MW (Unit 10) combination natural gas-fired and oil fired combustion turbine/generator at the site. The coal-fired boilers and steam turbine/generators are housed in a metal sided boiler and turbine building. The combustion turbine/generator is housed in a stand alone metal sided building which also includes a diesel generator for "black start" service. The Plant proper is located on Lake Michigan and includes an intake crib located in the lake connected by buried pipe to a water intake building located on the shoreline for water makeup and cycle cooling. A discharge flume is located adjacent to the water intake building for discharge into Lake Michigan.

1.2 RESULTS

When NIPSCO determines that the Plant facilities should be demolished, the above grade equipment and steel structures are assumed to have significant scrap value to a salvage contractor. The scrap value of these items will be used as a credit against the demolition costs. However, NIPSCO will incur costs in the restoration of the site following the removal of salvageable equipment.

The asset demolition costs were developed for two scenarios. The first scenario was based on leaving the site in an industrial condition, with below grade foundations and structures remaining on-site, and an on-site inert waste landfill. The second scenario was based on returning the site to a greenfield condition with no structures remaining, compatible with the surrounding land, similar to the conditions that existed before development of the Plant.

Based on the results of the Asset Demolition Study conducted for the Bailly Generating Station, the estimated demolition costs in current dollars (2008 $) are summarized in Table 1.1 below.

Table 1.1

Demolition Cost Estimate Summary

Option	Total Cost	Project Duration
Full Demolition, Industrial Site	$ 29,379,000	24 Months
Full Demolition, Greenfield Site	$ 64,211,000	30 Months

* * * * *

2.0 PLANT SITE

2.1 SITE VISIT

Representatives from B&McD visited the Plant on April 8, 2008. The purpose of the site visit was to gather information to conduct the Asset Demolition Study, interview the Plant management and operations staff, and to conduct an on-site review of the Plant facilities. The following B&McD representatives comprised the Asset Demolition Study team:

- Mr. Vic Ranalletta, Engineering Manager, Mechanical Engineer
- Mr. Jeff Grubich, Environmental Engineer
- Mr. Mark Sarceda, Mechanical Engineer

2.2 PLANT DESCRIPTION

The Bailly Generating Station includes coal-fired units consisting of two coal-fired boilers and steam turbine/generators. One of the coal-fired units is rated at 160 MW (Unit 7) and the other is rated at 320 MW (Unit 8). In addition to the coal-fired boilers, there is a 31 MW (Unit 10) natural gas-fired combustion turbine/generator at the site. The coal-fired boilers and steam turbine/generators are housed in a metal sided boiler and turbine building. The Unit 7 and 8 boilers share a common concrete stack with individual flue liners.

The coal-fired units each include an electrostatic precipitator (ESP) and selective catalytic reduction (SCR) system. Unit 8 has a soda ash unloading, storage, and pumping system located in a metal-sided building west of the power house. A common flue gas sulfur dioxide removal scrubber system serves both coal-fired units. The scrubber system includes the following: scrubber modules; slurry pump building; air compressor and receiver building; concrete storage silos for powdered limestone; hydrated lime powder storage tank; administration building to serve the scrubber operation; lime truck unloading area. Gypsum production is the by-product of the scrubber system. Pure Air is a private commercial concern that owns, operates, and maintains the scrubber system under a lease agreement with NIPSCO. The gypsum storage "A" frame building is owned and operated by NIPSCO. NIPSCO subcontracts with a material handling company for loading & hauling of the gypsum to a wall board manufacturing plant off site..

Several levels of subgrade concrete basement structure exist below the turbine floor where ancillary equipment for the Units resides. The turbine or operating floor for each Unit is at the natural grade elevation. The subgrade structure houses the intake traveling screens, circulating water pumps, surface condensers, condensate pumps, and other ancillary equipment and systems for the Units, auxiliary transformers, motor control centers (MCCs) and switchgear.

The service building is a two story brick building attached to the west side of the Unit 8 turbine building.

Coal is delivered to the Plant by rail cars indexed by a car indexer one by one through a thaw shed into an elevated rotary car unloader. Empty single rail cars roll by gravity to a reversing ramp that reverses the rolling direction of the car back to a staging rail yard. Coal is conveyed from the unloader to a transfer house where the coal either is directed to a radial stacker out to an open coal pile, or to the coal crusher house. A series of conveyors and transfer houses move crushed coal to the tripper conveyors located above the coal bunkers located between the boiler and turbine rooms.

Unit 10 is located in a stand alone metal sided building which also includes a diesel generator for "black start" service. A fuel oil tank is located adjacent to the Unit 10 building. The fuel oil tank has been emptied and cleaned and is no longer in use.

Bottom ash from the boilers is sluiced to primary ponds located southeast of the main plant. Ash pond water cascades to secondary ponds for further settling of the suspended ash particles. A water recycling pump house located adjacent to the secondary ponds pump water back to the Plant's ash conveying systems.

* * * * *

3.0 SITE DEMOLITION

Two separate cost estimates were prepared for different site demolition scenarios. The first option evaluated included removal of all above grade equipment, piping, and wiring relating at the site, including the buildings, but leaving the foundations and below grade piping and wiring in-place, to return the area to an industrial site. The second scenario included removal of all above grade equipment, piping, wiring at the site, including the buildings, foundations and below grade piping and wiring, to return the area to a greenfield site. A breakdown of each of the demolition cost estimates is provided in Appendix A.

3.1 OPTION 1 – FULL DEMOLITION, INDUSTRIAL SITE

This Option includes removing all equipment at the site, as well as the building structure, but leaving the foundations and below grade piping and wiring in place. All asbestos will be removed, as well as any PCBs, and mercury. The equipment will then be removed and the building demolished. The foundations will remain in place, and the subgrade structure will be used as a repository for inert demolition debris. Underground piping will be capped and abandoned in-place and underground wiring and bus duct will be abandoned in-place.

The estimated cost for this demolition option is $29,379,000.

3.1.1 General Cost Assumptions and Clarifications

The following items are included in the cost estimate:

- All estimates are budgetary in nature and do not reflect guaranteed costs.
- All estimates are based on union labor.
- Sufficient area to receive, assemble and temporarily store equipment and materials is available.
- All cost estimates are in current 2008 dollars.
- The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition, therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap at the time of site demolition.
- All oils must be confirmed to be polychlorinated biphenyl (PCB) free. If any PCBs are discovered, they will be disposed of properly. Concrete pads and/or flooring surrounding internal transformers will be removed and properly disposed.

- Impacted soils surrounding exterior transformers will be removed to approximately 3 feet below ground surface and disposed of properly.
- All asbestos-based materials will be removed and disposed of in accordance with EPA and OSHA regulations. Transite wall paneling, floor tile, ceiling tile and all other asbestos-containing materials will be removed from all structures and disposed of off-site in accordance with state regulations. The costs include scaffolding necessary to complete the work.
- Batteries, including lead and nickel cadmium batteries will be removed and recycled or disposed of properly. Concrete flooring in battery rooms will be removed and properly disposed.
- Mercury filled equipment and instruments will be removed and disposed of or recycled. Other materials including flooring will be separated from the demolition debris and disposed of properly. Mercury impacted electrical equipment in control rooms will be disposed of properly.
- Freon will be removed and disposed of properly.
- All environmental related costs were obtained through data and information collected during site visits and discussions with NIPSCO operations and NIPSCO environmental employees. NIPSCO environmental costs were used for the historic contamination associated with Solid Waste Management Units (SWMUs). These costs were reviewed and professional judgment was made to ensure that the costs were reasonable and appropriate.
- All waste products such as solvents and oils located in maintenance facilities will be removed and properly disposed. In addition, concrete flooring and impacted soils will be removed and properly disposed.
- OSHA HAZWOPER-trained construction workers will be used to remove arsenic-coated steel in boilers.
- OSHA HAZWOPER-trained construction workers will be used to remove lead-based paint coated steel.
- Gauges containing low-level radioactive materials will be removed and disposed of properly.
- Above grade piping and all tanks will be removed and disposed of properly. Petroleum impacted soils associated with oil piping and both aboveground and underground storage tanks will be removed and disposed of properly.
- All above grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished to grade.
- All above grade plant structures will be demolished to grade. All other building and structure materials such as elevated concrete floors, concrete pedestals above grade, fire walls, masonry, doors,

windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable trays, etc. will be disposed of in the on-site inert waste landfill where possible.

- An on-site inert waste landfill will be utilized for demolition debris consisting of brick, block, concrete and any other materials that fall under the inert waste category. The vault structure beneath the steam turbine generators will serve as the primary location for the inert waste landfill.
- The ground level concrete slab and structural steel framing around the steam turbine generator foundations will be removed. A temporary fence will be placed around the open vault until the vault is filled to grade with inert waste material from demolition operations and soil filled. This will serve as the on-site inert debris landfill.
- Onsite solid waste management units will be properly remediated under RCRA as part of this option.
- All coal in storage will be burned prior to decommissioning.
- The coal handling and storage area will be capped with 1 foot of soil material and seeded. Sufficient on-site material for capping is not available at the Bailly facility, therefore, off-site material will be used for capping the coal handling and storage area.
- Water will be drained from the coal pile runoff pond located north of the coal yard. Sludge and contaminated soil will be stabilized, excavated, and disposed of at an off-site landfill as a hazardous material.
- The coal storage yard will be covered with topsoil, graded for drainage and seeded. Vegetation will be re-established in the coal pile runoff pond, and it will function as a stormwater runoff surge pond for the coal yard area.
- Openings in the coal unloading and reclaim hopper structures will be sealed with concrete and covered with three feet of fill above existing grade after equipment is removed and drains plugged.
- The above ground conveyors and structures, stackers, transfer houses, conveyor tunnel portals, and crusher house will be demolished. To the extent practical, structural steel and conveyor components will be scrapped. All other building materials, i.e. concrete, brick, etc., will be disposed of in the on-site inert waste landfill where possible.
- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly.
- Ash storage silos/structures, ash piping, pipe racks, and associated equipment will be demolished to grade and scrapped. The exposed foundations will be covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- All remaining plant structures and yard buildings will be demolished. Building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade,

masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in the on-site inert waste landfill where possible.

- Below grade foundations and ground floor slabs will be left in place and covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- Underground piping systems will be purged of all oils or chemicals other than water, excavated and disposed of properly.
- Lake Michigan make up water system, intake structures, intake screens, electrical equipment, and building located on land will be removed and salvaged or scrapped. The wood timber and rock intake crib located in Lake Michigan will be abandoned in place.
- All portable tanks will be removed from the site, including any propane tanks, oil storage tanks, chemical totes and waste oil tanks.
- All chemicals will be consumed prior to shut down or disposed of properly, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
- All trash debris and miscellaneous waste will be removed and disposed of properly.
- Water will be drained from all on-site ash and settling ponds. Berm material will be graded into the ponds prior to capping. The ash ponds will be covered with 6 inches of soil followed by a low permeability geomembrane liner overlaid with a final protective vegetative cover of 2 feet of soil, which will be graded for drainage, and seeded. The remaining ponds will be covered with a minimum of 2 feet of soil, graded to drain and seeded. On-site material for capping is not available at the Bailly facility, therefore, off-site material will be used for capping.
- Groundwater monitoring wells will be installed for the closed ponds.
- Equipment spare parts will be removed and sold.
- Plant mobile maintenance equipment and shop maintenance equipment will be removed and salvaged.
- Universal wastes present in office areas that require special handling and disposal such as mercury in fluorescent bulbs and thermostats and PCB contaminated ballasts will be segregated and properly disposed.
- Universal wastes present throughout the remaining areas of the plant that require special handling and disposal such as mercury vapor bulbs and ballasts and fluorescent lighting bulbs and ballasts will be segregated and properly disposed.

3.1.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalation
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition
- Transmission or distribution (non-generation) substation modifications or relocation.

3.2 OPTION 2 – FULL DEMOLITION, GREENFIELD SITE

This option includes returning the plant to a Greenfield site condition. Under this scenario, an on-site inert debris landfill would not be used. This cost estimate would include the additional costs associated with hauling all demolition debris off site and also removing below grade foundations, equipment and structures. All underground piping and duct bank would be excavated and removed as well.

The estimated cost for this demolition option is $64,211,000.

3.2.1 General Cost Assumptions and Clarifications

The following items are included in the greenfield cost estimate in addition to or replacement of the assumptions stated for the industrial site closure:

- Impacted soils surrounding exterior transformers will be removed to approximately 10 feet below ground surface and disposed of properly.
- Below grade piping and all tanks will be removed and disposed of properly.
- All below grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished including subsurface structures.
- All above grade plant structures will be demolished including subsurface structures. Building and structure materials such as elevated concrete floors, concrete pedestals above grade, subsurface structures, fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc., will be disposed of in an off-site landfill.
- A total of 1 foot of material in the coal handling and storage areas will be removed and disposed of at an off-site landfill as a hazardous material. One foot of offsite material will be brought to the facility to replace the material removed and vegetated.

- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly. Impacted soil surrounding the rail lines will be excavated to approximately 1 foot below ground surface and properly disposed.
- All remaining plant structures and yard buildings will be demolished. All building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in an off-site landfill.
- Below grade foundations and ground floor slabs will be demolished and the debris disposed of in an off site landfill.
- The entire Lake Michigan intake and outfall structures will be demolished and the debris disposed of in an off site landfill. After removal of the intake and outfall structures, the disturbed areas will be graded as required to match the surrounding grade.
- All fixed equipment and below-grade storage vessels will be removed from the site.

3.2.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalation
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition
- Transmission or distribution (non-generation) substation modifications or relocation.

3.3 BULK SCRAP MATERIAL VALUE

Burns & McDonnell estimated the quantity of some bulk scrap materials that could be used to offset demolition costs. However, due to the complexity of a power plant and the scope of this study, a complete estimate of quantities can not be provided.

The value of these scrap materials was estimated based on recent market prices for bulk scrap. The scrap material prices use for this study were as reported in the March 2008 prices for scrap metal for the Upper

Mid-West in the "Demolition Scrap Value and Metal News." The values of scrap quantities utilized in the study are as follows:

- Carbon Steel $230/ton
- Copper $5320/ton

* * * * *

4.0 LIMITATIONS

In preparation of this Asset Demolition Study, B&McD has relied upon information provided by NIPSCO. The information provided by NIPSCO included site and equipment drawings, asbestos remediation estimates prepared by their asbestos contractor Insulco, historic contamination associated with Solid Waste Management Units, and general discussions of the plants during site visits. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of demolition costs are based on Engineer's experience, qualifications and judgment. Weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors at the time of demolition will affect the accuracy of the estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

*****

APPENDIX A – DEMOLITION COST BREAKDOWNS

Petitioner's Exhibit VFR-3
Northern Indiana Public Service Company
Cause No. 43526

Burns & McDonnell
SINCE 1898

TABLE A.1

BAILLY GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Plant to Industrial Site

Task	Description	Costs	Credits
1	Environmental Remediation	$18,130,257	$0
2	Building Concrete Removal - Above Grade	$2,609,476	$0
3	Building Structural Steel Removal - Above Grade	$4,406,554	$0
4	Major Equipment Removal		
	a Boilers Demolition	$2,745,470	$0
	b Turbine and Condenser Removal	$613,870	$0
	c Chimney Demolition	$134,399	$0
	d Precipitator Demolition	$193,273	$0
	e SCR Demolition	$1,590,560	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$388,192	$0
	b FGD Demolition	$1,525,752	$0
	c Ash Handling Equipment Demolition	$168,827	$0
	d Miscellaneous Mechanical Equipment Demolition	$1,573,552	$0
	e Miscellaneous Piping and Hanger Demolition	$767,669	$0
6	Plant Electrical Systems		
	a Transformer Removal	$74,896	$0
	b Electrical Equipment Demolition	$365,143	$0
	c Electrical Controls Demolition	$433,397	$0
	d Miscellaneous Wiring and Buswork Demolition	$417,797	$0
7	Credit for filling in Turbine, Boiler, Service and Admin Building Foundations	$0	($7,019,014)
8	Scrap Value		
	a Steel	$0	($7,060,383)

Burns & McDonnell SINCE 1898

TABLE A.1

BAILLY GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Plant to Industrial Site

Task	Description	Costs	Credits
b	Copper	$0	($31,920)
c	Equipment	$0	($4,428,435)
	TOTAL COST (CREDIT)	**$36,139,000**	**($18,540,000)**
	PROJECT INDIRECTS		
	Contractor Indirects 5% of Total Cost	$1,807,000	
	Engineering	$542,000	
	Construction Management	$740,000	
	Owner Indirects	$723,000	
	Performance Bond	$740,000	
	CONTINGENCY (20%)	$7,228,000	
	TOTAL PROJECT COST (CREDIT)	**$47,919,000**	**($18,540,000)**
	TOTAL NET PROJECT COST (CREDIT)	**$29,379,000**	

Burns & McDonnell SINCE 1898

TABLE A.2

BAILLY GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

Task	Description	Costs	Credits
1	Environmental Remediation	$24,396,640	$0
2	Building Concrete Removal - Above Grade	$2,609,476	$0
3	Building Structural Steel Removal - Above Grade	$4,406,554	$0
4	Major Equipment Removal		
	a Boilers Demolition	$2,745,470	$0
	b Turbine and Condenser Removal	$613,870	$0
	c Chimney Demolition	$134,399	$0
	d Precipitator Demolition	$193,273	$0
	e SCR Demolition	$1,590,560	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$388,192	$0
	b FGD Demolition	$1,525,752	$0
	c Ash Handling Equipment Demolition	$168,827	$0
	d Miscellaneous Mechanical Equipment Demolition	$1,573,552	$0
	e Miscellaneous Piping and Hanger Demolition	$767,669	$0
6	Plant Electrical Systems		
	a Transformer Removal	$74,896	$0
	b Electrical Equipment Demolition	$365,143	$0
	c Electrical Controls Demolition	$433,397	$0
	d Miscellaneous Wiring and Buswork Demolition	$417,797	$0
7	Below Grade Demolition		
	a Boiler Building	$2,308,733	$0
	b Turbine Building	$3,765,361	$0
	c Service Building	$239,934	$0

Burns & McDonnell
SINCE 1898

TABLE A.2

BAILLY GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

Task	Description	Costs	Credits
	d Balance of Plant Buildings	$3,881,914	$0
	e Circulating Water Pipe Demolition	$105,930	$0
	f Below Grade Other Piping Demolition	$113,696	$0
	g Below Grade Busduct Demolition	$3,325,375	$0
8	Scrap Value		
	a Steel	$0	($7,066,454)
	b Copper	$0	($43,092)
	c Equipment	$0	$ (4,442,321)
11	Site Restoration	$1,414,000	$0
TOTAL COST (CREDIT)		**$57,560,000**	**$ (11,552,000)**
PROJECT INDIRECTS			
	Contractor Indirects 5% of Total Cost	$2,878,000	
	Engineering	$863,000	
	Construction Management	$740,000	
	Owner Indirects	$1,151,000	
	Performance Bond	$1,059,000	
CONTINGENCY (20%)		$11,512,000	
TOTAL PROJECT COST (CREDIT)		**$75,763,000**	**($11,552,000)**
TOTAL NET PROJECT COST (CREDIT)		**$64,211,000**	

Petitioner's Exhibit VFR-4
Northern Indiana Public Service Company
Cause No. 43526

Report on the

Asset Demolition Study
Mitchell Generating Station

for

Northern Indiana Public Service Company
Valparaiso, Indiana

Project Number 48492

June 20, 2008

Burns & McDonnell
SINCE 1898

Petitioner's Exhibit VFR-4
Northern Indiana Public Service Company
Cause No. 43526

Asset Demolition Study
Mitchell Generating Station

prepared for

Northern Indiana Public Service Company
Valparaiso, Indiana

June 20, 2008

Project No. 48492

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

Petitioner's Exhibit VFR-4
Northern Indiana Public Service Company
Cause No. 43526

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Asset Demolition Study
Mitchell Generating Station

Project 48492

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1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Burns & McDonnell (B&McD) was retained by Northern Indiana Public Service Company to conduct an Asset Demolition Study of the Mitchell Generating Station (Plant). The purpose of the Asset Demolition Study was to review the Plant facilities and to provide an estimate to NIPSCO regarding the total cost of complete demolition of the Units. The following report documents our efforts on this study.

The Mitchell Generating Station is a coal-fired Plant consisting of four coal-fired boilers and steam turbine/generators. Three of the four coal-fired units are rated at 125 MW and the fourth is rated at 110 MW. In addition to the coal-fired boilers, there is a 17 MW natural gas-fired combustion turbine/generator at the site. The coal-fired boilers and steam turbine/generators are housed in a metal sided boiler and turbine building. The Plant proper is located on Lake Michigan and includes a water intake and discharge structure for cooling water.

1.2 RESULTS

When NIPSCO determines that the Plant facilities should be demolished, the above grade equipment and steel structures are assumed to have significant scrap value to a salvage contractor. The scrap value of these items will be used as a credit against the demolition costs. However, NIPSCO will incur costs in the restoration of the site following the removal of salvageable equipment.

The asset demolition costs were developed for two scenarios. The first scenario was based on leaving the site in an industrial condition, with below grade foundations and structures remaining on-site, and an on-site inert waste landfill. The second scenario was based on returning the site to a greenfield condition with no aboveground or below ground structures remaining, compatible with the surrounding land, similar to the conditions that existed before development of the Plant.

Based on the results of the Asset Demolition Study conducted for the Mitchell Generating Station, the estimated demolition costs in current dollars (2008 $) are summarized in Table 1.1 below.

Table 1.1

Demolition Cost Estimate Summary

Option	Total Cost	Project Duration
Full Demolition, Industrial Site	$ 61,596,000	30 Months
Full Demolition, Greenfield Site	$ 84,248,000	38 Months

* * * * *

2.0 PLANT SITE

2.1 SITE VISIT

Representatives from B&McD visited the Plant on April 8, 2008. The purpose of the site visit was to gather information to conduct the Asset Demolition Study, interview the Plant management and operations staff, and to conduct an on-site review of the Plant facilities. The following B&McD representatives comprised the Asset Demolition Study team:

- Mr. Vic Ranalletta, Engineering Manager, Mechanical Engineer
- Mr. Lawrence Fieber, Environmental Geologist
- Mr. Jeff Grubich, Environmental Engineer
- Mr. Mark Sarceda, Mechanical Engineer

2.2 PLANT DESCRIPTION

The Mitchell Generating Station includes coal-fired units consisting of four coal-fired boilers and steam turbine/generators. Three of the four coal-fired units are rated at 125 MW (Units 4, 5, and 6) and the fourth is rated at 110 MW (Unit 11). In addition to the coal-fired boilers, there is a 17 MW (Unit 9) natural gas combustion turbine/generator at the site. The coal-fired boilers and steam turbine/generators are housed in a metal-sided boiler and turbine building. The boiler and turbine building consists of: turbine hall housing the condensers, pumps, deaerators; a building bay for the coal bunkers, coal mills, and tripper conveyer gallery; a service building housing the control room, battery rooms, cable spreading rooms; boiler building housing the boilers, fans, The coal-fired units each include an electrostatic precipitator to collect fly ash. A common fly ash silo and truck-loading system serves all the coal-fired units.

The Unit 4 and 5 boilers share a common steel stack. The Unit 6 and 11 boilers share a common steel stack.

The Plant equipment inside the main power house and outside is at or above the natural ground level, which is approximately 8 to 10 feet above the water level in Lake Michigan. A "once through" circulating water system is supplied by a common lake intake structure and plume. Warm condenser water is discharged back to the lake from each unit in a common discharge flume.

The Plant includes an on-site, open pile, coal storage yard and coal handling facilities, which include a loop track for storing rail cars, a rotary car unloader and building, thaw shed, underground reclaim and stacking conveyors in concrete tunnels, a push wall for dozer reclaiming from the open pile, coal crusher and drive house, and main conveyor from the crusher house to the tripper floor.

The Plant includes several demineralized water storage tanks elevated potable water tanks, and a fuel oil tank for Unit 9. The fuel oil tank has been emptied and cleaned and is no longer in use.

The Plant includes various metal-sided buildings for parts storage and operating personnel.

Electrical energy generated in the Plant is transmitted through unit generator step up (GSU) transformers to isolated phase bus ducts connected to a high voltage transmission substation. The Plant is back fed electrical energy from the substation through the isolated phase bus ducts connected to the Station auxiliary transformer. The substation includes a control house that contains the control relaying, batteries, SCADA and other support systems.

* * * * *

3.0 SITE DEMOLITION

Two separate cost estimates were prepared for different site demolition scenarios. The first option evaluated included removal of all above grade equipment, piping, and wiring relating at the site, including the buildings, but leaving the foundations and below grade piping and wiring in-place, to return the area to an industrial site. The second scenario included removal of all above grade equipment, piping, wiring at the site, including the buildings, foundations and below grade piping and wiring, to return the area to a greenfield site. A breakdown of each of the demolition cost estimates is provided in Appendix A.

3.1 OPTION 1 – FULL DEMOLITION, INDUSTRIAL SITE

This Option includes removing all equipment at the site, as well as the building structure, but leaving the foundations and below grade piping and wiring in place. All asbestos will be removed, as well as any PCBs, and mercury. The equipment will then be removed and the building demolished. The foundations will remain in place, and the subgrade structure will be used as a repository for inert demolition debris. Underground piping will be capped and abandoned in-place and underground wiring and busduct will be abandoned in-place.

The estimated cost for this demolition option is $61,596,000.

3.1.1 General Cost Assumptions and Clarifications

The following items are included in the cost estimate:

- All estimates are budgetary in nature and do not reflect guaranteed costs.
- All estimates are based on union labor.
- Sufficient area to receive, assemble and temporarily store equipment and materials is available.
- All cost estimates are in current 2008 dollars.
- The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition, therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap at the time of site demolition.
- All oils must be confirmed to be polychlorinated biphenyl (PCB) free. If any PCBs are discovered, they will be disposed of properly. Concrete pads and/or flooring surrounding internal transformers will be removed and properly disposed.

- Impacted soils surrounding exterior transformers will be removed to approximately 3 feet below ground surface and disposed of properly.
- All asbestos-based materials will be removed and disposed of in accordance with EPA and OSHA regulations. Transite wall paneling, floor tile, ceiling tile and all other asbestos containing materials will be removed from all structures and disposed of off-site in accordance with state regulations. The costs include scaffolding necessary to complete the work.
- Batteries, including lead and nickel cadmium batteries will be removed and recycled or disposed of properly. Concrete flooring in battery rooms will be removed and properly disposed.
- Mercury filled equipment and instruments will be removed and disposed of or recycled. Other materials including flooring will be separated from the demolition debris and disposed of properly. Mercury impacted electrical equipment in control rooms will be disposed of properly.
- Freon will be removed and disposed of properly.
- All environmental related costs were obtained through data and information collected during site visits and discussions with NIPSCO operations and NIPSCO environmental employees. NIPSCO environmental costs were used for the historic contamination associated with Solid Waste Management Units (SWMUs). These costs were reviewed and professional judgment was made to ensure that the costs were reasonable and appropriate.
- All waste products such as solvents and oils located in maintenance facilities will be removed and properly disposed. In addition, concrete flooring and impacted soils will be removed and properly disposed.
- OSHA HAZWOPER trained construction workers will be used to remove arsenic coated steel in boilers.
- OSHA HAZWOPER trained construction workers will be used to remove lead based paint coated steel.
- Gauges containing low-level radioactive materials will be removed and disposed of properly.
- Above grade piping and all tanks will be removed and disposed of properly. Petroleum impacted soils associated with oil piping and both aboveground and underground storage tanks will be removed and disposed of properly.
- All above grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished to grade.
- All above grade plant structures will be demolished to grade. All other building and structure materials such as elevated concrete floors, concrete pedestals above grade, fire walls, masonry, doors,

windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc., will be disposed of in the on-site inert waste landfill where possible.

- An on-site inert waste landfill will be utilized for demolition debris consisting of brick, block, concrete and any other materials that fall under the inert waste category. The on-site ponds and landfill will serve as the primary location for the inert waste landfill.
- Onsite solid waste management units will be properly remediated under RCRA as part of this option.
- The coal handling and storage area will be capped with 1 foot of soil material and seeded. Sufficient on-site material for capping is not available at the Mitchell facility, therefore, off-site material will be used for capping the coal handling and storage area.
- Water will be drained from the coal pile runoff pond located east of the coal yard. Sludge and contaminated soil will be stabilized, excavated, and disposed of at an off-site landfill as a hazardous material.
- The coal storage yard will be covered with topsoil, graded for drainage and seeded. Vegetation will be re-established in the coal pile runoff pond, and it will function as a stormwater runoff surge pond for the coal yard area.
- Openings in the coal unloading and reclaim hopper structures will be sealed with concrete and covered with three feet of fill above existing grade after equipment is removed and drains plugged.
- The above ground conveyors and structures, stacking tubes, transfer houses, conveyor tunnel portals, and crusher house will be demolished. To the extent practical, structural steel and conveyor components will be scrapped. All other building materials, i.e. concrete, brick, etc., will be disposed of in the on-site inert waste landfill where possible.
- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly.
- Ash storage silos/structures, ash piping, pipe racks, and associated equipment will be demolished to grade and scrapped. The exposed foundations will be covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- All remaining plant structures and yard buildings will be demolished. Building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in the on-site inert waste landfill where possible.
- Below grade foundations and ground floor slabs will be left in place and covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.

- Underground piping systems will be purged of all oils or chemicals other than water, excavated and disposed of properly.
- All portable tanks will be removed from the site, including any propane tanks, oil storage tanks, chemical totes and waste oil tanks.
- All chemicals will be consumed prior to shut down or disposed of properly, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
- All trash debris and miscellaneous waste will be removed and disposed of properly.
- Water will be drained from all on-site ash and settling ponds. Berm material will be graded into the ponds prior to capping. The ash ponds will be covered with 6 inches of soil followed by a low permeability geomembrane liner overlaid with a final protective vegetative cover of 2 feet of soil, which will be graded for drainage, and seeded. The remaining ponds will be covered with a minimum of 2 feet of soil, graded to drain and seeded. On-site material for capping is not available at the Mitchell facility, therefore, off-site material is used for capping.
- Groundwater monitoring wells will be installed for the closed ponds.
- Equipment spare parts will be removed and sold.
- Plant mobile maintenance equipment and shop maintenance equipment will be removed and salvaged.
- Universal wastes present in office areas that require special handling and disposal such as mercury in fluorescent bulbs and thermostats and PCB contaminated ballasts will be segregated and properly disposed.
- Universal wastes present throughout the remaining areas of the plant that require special handling and disposal such as mercury vapor bulbs and ballasts and fluorescent lighting bulbs and ballasts will be segregated and properly disposed.

3.1.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalation
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- No costs related to any changes to Lake Mitchell are included. It is to remain as-is.
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition

- Transmission or distribution (non-generation) substation modifications or relocation.

3.2 OPTION 2 – FULL DEMOLITION, GREENFIELD SITE

This option includes returning the plant to a greenfield site condition. Under this scenario, an on-site inert debris landfill would not be used. This cost estimate would include the additional costs associated with hauling all demolition debris off site and also removing below grade foundations, equipment and structures. All underground piping and duct bank would be excavated and removed as well.

The estimated cost for this demolition option is $84,248,000.

3.2.1 General Cost Assumptions and Clarifications

The following items are included in the cost estimate in addition to or replacement of the assumptions stated for the industrial site closure:

- Impacted soils surrounding exterior transformers will be removed to approximately 10 feet below ground surface and disposed of properly.
- Below grade piping and all tanks will be removed and disposed of properly.
- All below grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished including subsurface structures.
- All above grade plant structures will be demolished including subsurface structures. Building and structure materials such as elevated concrete floors, concrete pedestals above grade, subsurface structures, fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc., will be disposed of in an off-site landfill.
- A total of 1 foot of material in the coal handling and storage areas will be removed and disposed of at an off-site landfill as a hazardous material. One foot of offsite material will be brought to the facility to replace the material removed and revegetated.
- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly. Impacted soil surrounding the rail lines will be excavated to approximately 1 foot below ground surface and properly disposed.
- All remaining plant structures and yard buildings will be demolished. All building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in an off-site landfill.

- Below grade foundations and ground floor slabs will be demolished and the debris disposed of in an off site landfill.
- The entire river intake and outfall structures will be demolished and the debris disposed of in an off site landfill. After removal of the river intake and outfall structures, the areas will be covered with materials required to restore the original river bank line.
- All fixed equipment and below-grade storage vessels will be removed from the site.

3.2.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalations
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- No costs related to any changes to Lake Mitchell are included. It is to remain as-is.
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition
- Transmission or distribution (non-generation) substation modifications or relocation.

3.3 BULK SCRAP MATERIAL VALUE

Burns & McDonnell estimated the quantity of some bulk scrap materials that could be used to offset demolition costs. However, due to the complexity of a power plant and the scope of this study, a complete estimate of quantities can not be provided.

The value of these scrap materials was estimated based on recent market prices for bulk scrap. The scrap material prices use for this study were as reported in the March 2008 prices for scrap metal for the Upper Mid-West in the "Demolition Scrap Value and Metal News." The values of scrap quantities utilized in the study are as follows:

- Carbon Steel $230/ton
- Copper $5320/ton

* * * * *

4.0 LIMITATIONS

In preparation of this Asset Demolition Study, B&McD has relied upon information provided by NIPSCO. The information provided by NIPSCO included site and equipment drawings, asbestos remediation estimates prepared by their asbestos contractor Insulco, historic contamination associated with Solid Waste Management Units, and general discussions of the plants during site visits. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of demolition costs are based on Engineer's experience, qualifications and judgment. Weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors at the time of demolition will affect the accuracy of the estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

* * * * *

APPENDIX A – DEMOLITION COST BREAKDOWNS

Petitioner's Exhibit VFR-4
Northern Indiana Public Service Company
Cause No. 43526

Burns & McDonnell
SINCE 1898

TABLE A.1

MITCHELL GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Plant to Industrial Site

Task	Description	Costs	Credits
1	Environmental Remediation	$36,448,154	$0
2	Building Concrete Removal - Above Grade	$1,186,536	$0
3	Building Structural Steel Removal - Above Grade	$2,914,605	$0
4	Major Equipment Removal		
	a Boilers Demolition	$5,890,374	$0
	b Turbine and Condenser Removal	$423,751	$0
	c Chimney Demolition	$330,130	$0
	d Precipitator Demolition	$105,422	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$188,512	$0
	b FGD Demolition	$0	$0
	c Ash Handling Equipment Demolition	$330,983	$0
	d Miscellaneous Mechanical Equipment Demolition	$1,340,796	$0
	e Miscellaneous Piping and Hanger Demolition	$999,393	$0
6	Plant Electrical Systems		
	a Transformer Removal	$74,896	$0
	b Electrical Equipment Demolition	$365,143	$0
	c Electrical Controls Demolition	$433,397	$0
	d Miscellaneous Wiring and Buswork Demolition	$417,797	$0
7	Scrap Value		
	a Steel	$0	($4,726,273)
	b Copper	$0	($32,253)
	c Equipment	$0	($1,467,310)

Burns & McDonnell
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TABLE A.1

MITCHELL GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Plant to Industrial Site

Task Description	Costs	Credits
TOTAL COST (CREDIT)	**$51,450,000**	**($6,226,000)**
PROJECT INDIRECTS		
Contractor Indirects 5% of Total Cost	$2,573,000	
Engineering	$772,000	
Construction Management	$639,000	
Owner Indirects	$1,029,000	
Performance Bond	$1,069,000	
CONTINGENCY (20%)	$10,290,000	
TOTAL PROJECT COST (CREDIT)	**$67,822,000**	**($6,226,000)**
TOTAL NET PROJECT COST (CREDIT)	**$61,596,000**	

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TABLE A.2

MITCHELL GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

Task	Description	Costs	Credits
1	Environmental Remediation	$40,626,555	$0
2	Building Concrete Removal - Above Grade	$1,186,536	$0
3	Building Structural Steel Removal - Above Grade	$2,914,605	$0
4	Major Equipment Removal		
	a Boilers Demolition	$5,890,374	$0
	b Turbine and Condenser Removal	$423,751	$0
	c Chimney Demolition	$330,130	$0
	d Precipitator Demolition	$105,422	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$188,512	$0
	b FGD Demolition	$0	$0
	c Ash Handling Equipment Demolition	$330,983	$0
	d Miscellaneous Mechanical Equipment Demolition	$1,340,796	$0
	e Miscellaneous Piping and Hanger Demolition	$999,393	$0
6	Plant Electrical Systems		
	a Transformer Removal	$74,896	$0
	b Electrical Equipment Demolition	$365,143	$0
	c Electrical Controls Demolition	$433,397	$0
	d Miscellaneous Wiring and Buswork Demolition	$417,797	$0
7	Below Grade Demolition		
	a Boiler Building	$1,505,316	$0
	b Turbine Building	$708,564	$0
	c Service Building	$145,099	$0
	d Balance of Plant Buildings	$3,146,686	$0
	e Below Grade Other Piping Demolition	$200,352	$0

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TABLE A.2

MITCHELL GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

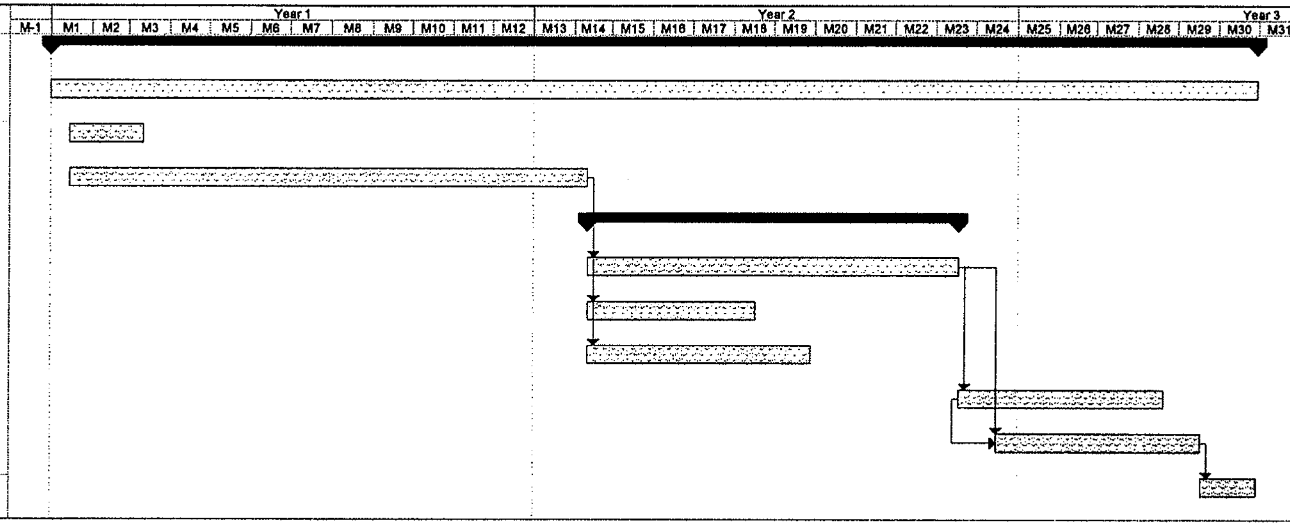
Task	Description	Costs	Credits
	f Below Grade Busduct Demolition	$5,903,230	$0
8	Scrap Value		
	a Steel	$0	($4,732,244)
	b Copper	$0	($43,541)
	c Equipment	$0	($1,518,569)
9	Site Restoration	$1,679,000	$0
TOTAL COST (CREDIT)		**$68,917,000**	**$ (6,294,000)**
PROJECT INDIRECTS			
	Contractor Indirects 5% of Total Cost	$3,446,000	
	Engineering	$1,034,000	
	Construction Management	$639,000	
	Owner Indirects	$1,378,000	
	Performance Bond	$1,345,000	
CONTINGENCY (20%)		$13,783,000	
TOTAL PROJECT COST (CREDIT)		**$90,542,000**	**($6,294,000)**
TOTAL NET PROJECT COST (CREDIT)		**$84,248,000**	

APPENDIX B – DEMOLITION SCHEDULES

Petitioner's Exhibit VFR-4
Northern Indiana Public Service Company
Cause No. 43526

MITCHELL GENERATING STATION
DEMOLITION SCHEDULE
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

ID	Task Name
1	DEMOLITION
2	NIPSCO SITE REPRESENTATIVE
3	NIPSCO DEMOLITION CONTRACTOR AWARD
4	ASBESTOS CONTRACTOR MOB, SITE WORK, DEMOB
5	EQUIPMENT DEMOLITION
6	MAJOR EQUIPMENT
7	PLANT MECHANICAL SYSTEMS
8	PLANT ELECTRICAL SYSTEMS
9	BUILDING STRUCTURAL STEEL REMOVAL - ABOVE GRADE
10	BUILDING CONCRETE REMOVAL - ABOVE GRADE
11	SITE RESTORATION & CLEANUP



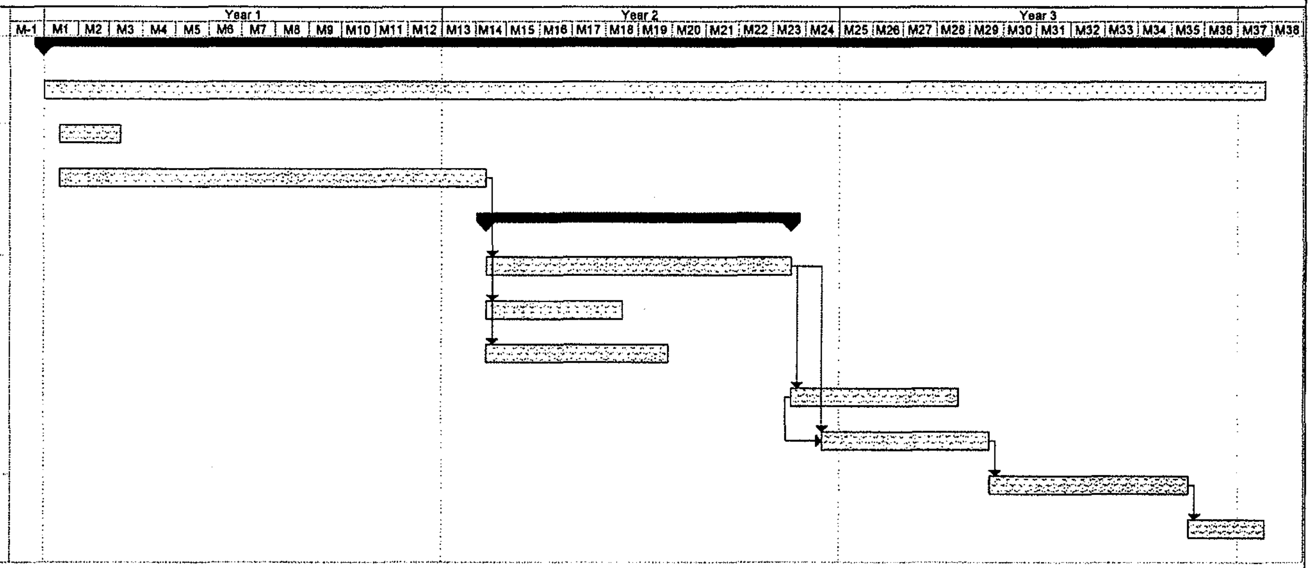
Project: NIPSCODEMOLITION - D H
Date: Tue 5/20/08

Task
Split
Progress
Milestone
Summary
Project Summary
External Tasks
External Milestone
Deadline

Petitioner's Exhibit VFR-4
Northern Indiana Public Service Company
Cause No. 43526

MITCHELL GENERATING STATION
DEMOLITION SCHEDULE
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

ID	Task Name
1	DEMOLITION
2	NIPSCO SITE REPRESENTATIVE
3	NIPSCO DEMOLITION CONTRACTOR AWARD
4	ASBESTOS CONTRACTOR MOB, SITE WORK, DEMOB
5	EQUIPMENT DEMOLITION
6	MAJOR EQUIPMENT
7	PLANT MECHANICAL SYSTEMS
8	PLANT ELECTRICAL SYSTEMS
9	BUILDING STRUCTURAL STEEL REMOVAL - ABOVE GRADE
10	BUILDING CONCRETE REMOVAL - ABOVE GRADE
11	BELOW GRADE DEMOLITION
12	SITE RESTORATION & CLEANUP



Project: NIPSCO DEMOLITION - D H Date: Tue 5/20/08	Task	Progress	Summary	External Tasks	Deadline
	Split	Milestone	Project Summary	External Milestone	

Petitioner's Exhibit VFR-5
Northern Indiana Public Service Company
Cause No. 43526

Report on the

Asset Demolition Study
Sugar Creek Generating Station

for

Northern Indiana Public Service Company
Valparaiso, Indiana

Project Number 48492

June 20, 2008

Burns & McDonnell
SINCE 1898

Petitioner's Exhibit VFR-5
Northern Indiana Public Service Company
Cause No. 43526

Asset Demolition Study
Sugar Creek Generating Station

prepared for

Northern Indiana Public Service Company
Valparaiso, Indiana

June 20, 2008

Project No. 48492

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX

Asset Demolition Study
Sugar Creek Generating Station

Project 48492

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2	Plant Site	1
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APPENDIX A – DEMOLITION COST BREAKDOWNS

* * * * *

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A.2 Demolition Cost Breakdown: Option 2 – Full Demolition, Greenfield Site

* * * * *

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Burns & McDonnell (B&McD) was retained by Northern Indiana Public Service Company to conduct an Asset Demolition Study of the Sugar Creek Generating Station (Plant). The purpose of the Asset Demolition Study was to review the Plant facilities and to provide an estimate to NIPSCO regarding the total cost of complete demolition of the Units. The following report documents our efforts on this study.

The Sugar Creek Generation Station is a 2x1 combined cycle power plant. The Facility consists of two (2) GE 7FA combustion turbines, two (2) Vogt triple pressure heat recovery steam generators (HRSGs), and a GE D11 condensing steam turbine generator. The Plant also includes an administration/control room building, warehouse, two plant switchyards, and a water tank.

1.2 RESULTS

When NIPSCO determines that the Plant facilities should be demolished, the above grade equipment and steel structures are assumed to have significant scrap value to a salvage contractor. The scrap value of these items will be used as a credit against the demolition costs. However, NIPSCO will incur costs in the restoration of the site following the removal of salvageable equipment.

The asset demolition costs were developed for two scenarios. The first scenario was based on leaving the site in an industrial condition, with below grade foundations and structures remaining on-site, and an on-site inert waste landfill. The second scenario was based on returning the site to a greenfield condition with no structures remaining, compatible with the surrounding land, similar to the conditions that existed before development of the Plant.

Based on the results of the Asset Demolition Study conducted for the Sugar Creek Generating Station, the estimated demolition costs in current dollars (2008 $) are summarized in Table 1.1 below.

Table 1.1
Demolition Cost Estimate Summary

Option	Total Cost	Project Duration
Full Demolition, Industrial Site	$ 2,175,000	6 Months
Full Demolition, Greenfield Site	$ 5,243,000	8 Months

* * * * *

2.0 PLANT SITE

2.1 SITE VISIT

Representatives from B&McD visited the Plant on September 13, 2007 as part of a due diligence evaluation performed on behalf of NIPSCO relating to the acquisition of the Plant. No additional site visit was conducted as part of this study. The following B&McD representatives visited the site as part of the due diligence team:

- Mr. Vic Ranalletta, Engineering Manager, Mechanical Engineer
- Mr. Mark Sarceda, Mechanical Engineer
- Mr. Chuck Bell, Environmental Specialist
- Mr. Mike Borgstadt, Development Engineer

2.2 PLANT DESCRIPTION

The Sugar Creek Generation Station is a 2x1 combined cycle power plant. The Facility consists of two (2) GE 7FA combustion turbines, two (2) Vogt triple pressure heat recovery steam generators (HRSGs), and a GE D11 condensing steam turbine generator. The Units are not enclosed in a building.

The Plant also includes an administration/control room building, warehouse, two plant switchyards, and a water tank.

* * * * *

3.0 SITE DEMOLITION

Two separate cost estimates were prepared for different site demolition scenarios. The first option evaluated included removal of all above grade equipment, piping, and wiring relating at the site, including the buildings, but leaving the foundations and below grade piping and wiring in place, to return the area to an industrial site. The second scenario included removal of all above grade equipment, piping, wiring at the site, including the buildings, foundations and below grade piping and wiring, to return the area to a greenfield site. A breakdown of each of the demolition cost estimates is provided in Appendix A.

3.1 OPTION 1 – FULL DEMOLITION, INDUSTRIAL SITE

This Option includes removing all equipment at the site, but leaving the foundations and below grade piping and wiring in place. The equipment will be removed and any on-site buildings demolished. The foundations will remain in place, and the stormwater retention pond and settling basins will be used as a repository for inert demolition debris. Underground piping will be capped and abandoned in place and underground wiring and bus duct will be abandoned in place.

The estimated cost for this demolition option is $2,175,000.

3.1.1 General Cost Assumptions and Clarifications

The following items are included in the cost estimate:

- All estimates are budgetary in nature and do not reflect guaranteed costs.
- All estimates are based on union labor.
- Sufficient area to receive, assemble and temporarily store equipment and materials is available.
- All cost estimates are in current 2008 dollars.
- The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition, therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap at the time of site demolition.
- Above grade piping and all tanks will be removed and disposed of properly.
- All above grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All above grade plant structures will be demolished to grade. All other building and structure materials such as elevated concrete floors, concrete pedestals above grade, fire walls, masonry, doors,

windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable trays, etc., will be disposed of in the on-site inert waste landfill where possible.

- An on-site inert waste landfill will be utilized for demolition debris consisting of brick, block, concrete and any other materials that fall under the inert waste category. The stormwater retention pond and settling basins will serve as the primary location for the inert waste landfill.
- Below grade foundations and ground floor slabs will be left in place and covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- Underground piping systems will be purged of all oils or chemicals other than water, plugged, and left in place.
- All portable tanks will be removed from the site, including any propane tanks, oil storage tanks, and waste oil tanks.
- Below grade piping will be capped and abandoned in place.
- All chemicals will be consumed prior to shut down or disposed of properly, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
- Any observable surface spill will be cleaned up.
- All trash debris and miscellaneous waste will be removed and disposed of properly.
- Water will be drained from all on-site ponds, the liner will be removed from the stormwater retention pond, and the ponds will be used as the on-site inert debris landfill.
- All existing alluvial wells and deep wells will be closed in accordance with state requirements.
- Equipment spare parts will be removed and sold.
- Plant mobile maintenance equipment and shop maintenance equipment will be removed and salvaged.
- The switchyard facilities that interconnect the plant to the PJM system and MISO system will be removed.

3.1.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Owner's indirect escalations
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition

- Transmission or distribution (non-generation) substation modifications or relocation. No transmission or distribution (non-generation) substation facilities are located on the site.

3.2 OPTION 2 – FULL DEMOLITION, GREENFIELD SITE

Option 2 includes returning the plant to a greenfield site condition. Under this scenario, an on-site inert debris landfill would not be used. This cost estimate would include the additional costs associated with hauling all demolition debris off site and also removing below grade foundations, equipment and structures. All underground piping and bus duct would be excavated and removed as well.

The estimated cost for this demolition option is $5,243,000.

3.2.1 General Cost Assumptions and Clarifications

The following items are included in the greenfield cost estimate in addition to or replacement of the assumptions stated for the industrial site closure:

- All above grade plant structures will be demolished to grade. All other building and structure materials such as elevated concrete floors, concrete pedestals above grade, fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc., will be disposed of in and off-site landfill.
- All remaining plant structures and yard buildings will be demolished. All building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in an off-site landfill.
- Below grade foundations and ground floor slabs will be demolished and the debris disposed of in an off-site landfill.
- Below grade piping will be excavated and removed.
- Water will be drained from all on-site ponds. The liner will be removed from the stormwater retention pond, and the ponds will be filled in with soil and graded to drain.

3.2.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing

- Owner's indirect escalations
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition
- Transmission or distribution (non-generation) substation modifications or relocation. No transmission or distribution (non-generation) substation facilities are located on the site.

3.3 BULK SCRAP MATERIAL VALUE

Burns & McDonnell estimated the quantity of some bulk scrap materials that could be used to offset demolition costs. However, due to the complexity of a power plant and the scope of this study, a complete estimate of quantities can not be provided.

The value of these scrap materials was estimated based on recent market prices for bulk scrap. The scrap material prices use for this study were as reported in the March 2008 prices for scrap metal for the Upper Mid-West in the "Demolition Scrap Value and Metal News." The values of scrap quantities utilized in the study are as follows:

- Carbon Steel $230/ton
- Copper $5320/ton

* * * * *

4.0 LIMITATIONS

In preparation of this Asset Demolition Study, B&McD has relied upon information provided by NIPSCO. The information provided by NIPSCO included site and equipment drawings and general discussions of the plants during site visits. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of demolition costs are based on Engineer's experience, qualifications and judgment. Since the Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

* * * * *

APPENDIX A – DEMOLITION COST BREAKDOWNS

Burns & McDonnell SINCE 1898

TABLE A.1

SUGAR CREEK GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Units to Industrial Site

Task	Description	Costs	Credits
1	Common Facilities		
	a Stormwater Retention Pond Liner Removal	$ 6,422	$ -
2	Building Removal		
	a Admin Building and Water Treatment Building Removal	$ 118,976	$ -
3	Powerblock Foundation Demolition		
	a Turbine Pedistal Demolition	$ 120,000	$ -
4	Major Equipment Removal		
	a Combustion Turbine Removal	$ 656,668	$ -
	b Steam Turbine Removal	$ 350,588	$ -
5	Plant Electrical Systems		
	a Transformer Removal	$ 110,808	$ -
	b Electrical Controls Demolition	$ 248,438	$ -
	c Electrical Controls Demolition	$ 359,574	$ -
	d Miscellaneous Wiring and Buswork Demolition	$ 137,034	$ -
6	Scrap Value		
	a Steel	$ -	$ (36,800)
	b Copper	$ -	$ (798,000)
	c Equipment	$ -	$ (361,100)

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TABLE A.1

SUGAR CREEK GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Units to Industrial Site

Task	Description		Costs		Credits
7	Site Restoration Costs				
	a Earthwork	$	307,000	$	-
	b Seeding	$	12,500	$	-
TOTAL COST (CREDIT)			**$2,428,000**	**$**	**(1,196,000)**
PROJECT INDIRECTS					
	Contractor Indirects 5% of Total Cost		$146,000		
	Engineering		$87,000		
	Construction Management		$58,000		
	Owner Indirects		$117,000		
	Performance Bond		$49,000		
CONTINGENCY (20%)			$486,000		
TOTAL PROJECT COST (CREDIT)			**$3,371,000**		**($1,196,000)**
TOTAL NET PROJECT COST (CREDIT)			**$2,175,000**		

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TABLE A.2

SUGAR CREEK GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

Task	Description	Costs	Credits
1	Common Facilities		
	a Paving Removal	$ 221,528	$ -
	b Crushed Rock Surfacing Removal	$ 248,750	$ -
	c Perimeter Fencing Removal	$ 28,000	$ -
	d Cooling Tower Foundation Removal	$ 219,488	$ -
	e Stormwater Retention Pond Liner Removal	$ 7,466	$ -
2	Building Removal		
	a Admin Building and Water Treatment Building Removal	$ 118,976	$ -
	b Building Foundation Removal	$ 377,627	$ -
3	Powerblock Foundation Demolition		
	a Turbine Pedistal Demolition	$ 146,325	$ -
	b Turbine Foundation Demolition	$ 402,394	$ -
4	Major Equipment Removal		
	a Combustion Turbine Removal	$ 656,668	$ -
	b Steam Turbine Removal	$ 350,588	$ -
5	Plant Electrical Systems		
	a Transformer Removal	$ 110,808	$ -
	b Electrical Controls Demolition	$ 248,438	$ -
	c Electrical Controls Demolition	$ 359,574	$ -
	d Miscellaneous Wiring and Buswork Demolition	$ 137,034	$ -

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TABLE A.2

SUGAR CREEK GENERATING STATION
DEMOLITION COST BREAKDOWN
OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Units to Greenfield

Task	Description	Costs	Credits
6	Scrap Value		
	a Steel	$ -	$ (36,800)
	b Copper	$ -	$ (798,000)
	c Equipment	$ -	$ (361,100)
7	Site Restoration Costs		
	a Earthwork	$ 921,000	$ -
	b Seeding	$ 90,000	$ -
TOTAL COST (CREDIT)		**$4,645,000**	**$ (1,196,000)**
PROJECT INDIRECTS			
	Contractor Indirects 5% of Total Cost	$279,000	
	Engineering	$167,000	
	Construction Management	$111,000	
	Owner Indirects	$223,000	
	Performance Bond	$85,000	
CONTINGENCY (20%)		$929,000	
TOTAL PROJECT COST (CREDIT)		**$6,439,000**	**($1,196,000)**
TOTAL NET PROJECT COST (CREDIT)		**$5,243,000**	

Petitioner's Exhibit VFR-6
Northern Indiana Public Service Company
Cause No. 43526

Report on the

Asset Demolition Study
Michigan City Units 2 & 3

for

Northern Indiana Public Service Company
Valparaiso, Indiana

Project Number 48492

June 20, 2008

Burns & McDonnell
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Petitioner's Exhibit VFR-6
Northern Indiana Public Service Company
Cause No. 43526

Asset Demolition Study
Michigan City Units 2 and 3

prepared for

Northern Indiana Public Service Company
Valparaiso, Indiana

June 20, 2008

Project No. 48492

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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Asset Demolition Study
Michigan City Units 2 and 3

Project 48492

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APPENDIX B – DEMOLITION SCHEDULE

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A.1 Demolition Cost Breakdown: Equipment Demolition, Buildings Remain

* * * * *

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Burns & McDonnell was retained by Northern Indiana Public Service Company to conduct an Asset Demolition Study of the Michigan City Units 2 & 3 (Units). The purpose of the Asset Demolition Study was to review the Unit 2 & 3 facilities and to provide an estimate to NIPSCO regarding the total cost of complete demolition of the Units. The following report documents our efforts on this study.

The Michigan City Units 2 & 3 are coal-fired units consisting of two steam turbine/generators and two boilers. The Units are housed in a brick building which includes three tall stacks. The Plant proper is located on Lake Michigan and includes a water intake and discharge structure for cooling water.

1.2 RESULTS

When NIPSCO determines that the Units should be demolished, the above grade equipment and steel structures are assumed to have significant scrap value to a salvage contractor. The scrap value of these items will be used as a credit against the demolition costs. However, NIPSCO will incur costs in the restoration of the site following the removal of salvageable equipment.

The asset demolition cost was developed for only removing the equipment, and leaving the buildings in place.

Based on the results of the Asset Demolition Study conducted for Michigan City Units 2 & 3, the estimated demolition cost in current dollars (2008 $) is summarized in Table 1.1 below.

Table 1.1
Demolition Cost Estimate Summary

	Total Cost	Project Duration
Equipment Demolition, Buildings Remain	$ 18,900,000	22 Months

* * * * *

2.0 PLANT SITE

2.1 SITE VISIT

Representatives from B&McD visited the Plant on March 6 and 19, 2008. The purpose of the site visit was to gather information to conduct the Asset Demolition Study, interview the Plant management and operations staff, and to conduct an on-site review of the Plant facilities. The following B&McD representatives comprised the Asset Demolition Study team:

- Mr. Vic Ranalletta, Engineering Manager, Mechanical Engineer
- Mr. Jeff Kopp, Development Engineer
- Mr. Tim Sobieraj, Structural Engineer
- Mr. Gary Herlitz , Electrical Engineer
- Mr. Lawrence Fieber, Environmental Geologist
- Mr. Jeff Pope, Environmental Engineer
- Mr. Jeff Grubich Environmental Engineer

2.2 PLANT DESCRIPTION

The Michigan City Units 2 & 3 are coal-fired units consisting of two remaining steam turbine/generators and three remaining boilers. The Units are housed in a brick building,. The Unit 2 & 3 steam turbine/generators are housed in the building, supported on a concrete turbine floor at approximately natural grade level (west elevation only).

The boilers are also housed in the building, and each boiler includes an individual, brick lined, steel stack.

Several levels of subgrade concrete basement structure exist below the turbine floor where ancillary equipment for the Units resides. The subgrade structure houses the circulating water pumps for the Units, several auxiliary transformers, batteries, and some switchgear.

The building also includes a coal conveyor and tripper system that previously delivered coal to the bunkers associated with each of the Units. Immediately adjacent to the building are electrostatic precipitators for the boilers. For the purpose of this study, the coal conveyor arch from the Unit down to the vertical interface with the abandoned coal breaker building north wall is included in this estimate.

The turbine room is flanked by a Plant office building on the west wall. The latter brick building includes the original structure and an addition. The Plant office building contains offices, conference rooms, control and relay panels, and battery banks for the electrical distribution substation located immediately to the west.

The boiler room is flanked by a Plant shop and stores building on the east wall. The latter brick building includes: the machine shop; tool room; laboratory; parts store room; offices.

* * * * *

3.0 SITE DEMOLITION

A single cost estimate was prepared for site demolition. The estimate was based on the removal of all equipment, piping, and wiring related to Units 2 & 3, to return the area to an industrial site and to leave the shell of the building in place. A breakdown of the demolition cost estimate is provided in Appendix A.

3.1 EQUIPMENT DEMOLITION, BUILDINGS REMAIN

This estimate includes the removal of all equipment associated with Units 2 & 3, but the buildings will remain in place. All asbestos will be removed, as well as any PCBs, and mercury. The equipment will then be removed from the building, as well as any piping, wiring, and HVAC equipment not necessary for continued operations of Unit 12. The shell of the building would remain in-place. Openings will have to be created in the building walls to allow access to the equipment for removal. The equipment will have to be cut up in place with torches in order to facilitate removal through the openings in the building. Some access openings are already available in the building from previous demolition work, as well as those that were included in the original building design to allow for equipment maintenance.

This will require more labor to remove the equipment from the buildings than if the building were to be demolished in order to minimize the building openings required and to ensure structural stability of the buildings to remain in place. Subsequent to removal of the equipment, the openings will have to be closed by placing paneling over the openings.

The estimated cost for this demolition activity is $18,900,000.

3.1.1 General Cost Assumptions and Clarifications

The following items are included in the cost estimate:

- All estimates are budgetary in nature and do not reflect guaranteed costs.
- All estimates are based on union labor.
- Sufficient area to receive, assemble and temporarily store equipment and materials is available.
- All cost estimates are in current 2008 dollars.
- The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition, therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap at the time of site demolition.

- All oils must be confirmed to be polychlorinated biphenyl (PCB) free. If any PCBs are discovered, they will be disposed of properly.
- All asbestos-based materials will be removed and disposed of in accordance with EPA and OSHA regulations. Transite wall paneling, floor tile, ceiling tile and all other asbestos containing materials will be removed from all structures and disposed of off-site in accordance with state regulations.
- Batteries, including lead and nickel cadmium batteries will be removed and disposed of or recycled.
- Mercury filled equipment and instruments will be removed and disposed of or recycled.
- Freon will be removed and disposed of properly.
- All environmental related costs were obtained through data and information collected during site visits and discussions with NIPSCO operations and NIPSCO environmental employees. NIPSCO environmental costs were used for the historic contamination associated with Solid Waste Management Units (SWMUs). These costs were reviewed and professional judgment was made to ensure that the costs were reasonable and appropriate.
- Above grade piping and all tanks will be removed and disposed of properly.
- All above grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- Solvents and oils located in the maintenance room will be removed and properly disposed of along with cleaning of the concrete flooring.
- Boiler refractory containing arsenic will be separated during demolition and properly disposed.
- Gauges containing low-level radioactive materials will be removed and disposed of properly.
- All three chimneys will be demolished.
- Below grade piping will be capped and abandoned in place.
- All fixed equipment and below-grade storage vessels containing petroleum products will be drained to the lowest possible level and removed from the site. The underground gasoline and fuel oil storage tanks will be removed from the site.
- Any observable surface spill will be cleaned up.
- All trash debris and miscellaneous waste will be removed and disposed of properly.
- Equipment spare parts will be removed and sold.

3.1.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalation

- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition
- Owner will cause all spare parts and contractor temporary shops/storage areas/working areas associated with Michigan City Units 2 & 3 to be removed prior to demolition
- Transmission or distribution (non-generation) substation modifications or relocation..

3.2 REQUIRED PLANT UPGRADES

In order to facilitate the removal of the equipment, but leave the shell of the building in place, openings will need to be cut in the walls as the roof of the building to remove the equipment. Subsequent to removal of the equipment, the openings will have to be closed by placing paneling over the openings. In addition, it is anticipated that some level of damage will be incurred in the brick facing of the building during the installation of the openings and removal of the equipment. Therefore, cost have been included to perform repairs to the brick facing in addition to covering the openings subsequent to equipment removal.

3.3 BULK SCRAP MATERIAL VALUE

Burns & McDonnell estimated the quantity of some bulk scrap materials that could be used to offset demolition costs. However, due to the complexity of a power plant and the scope of this study, a complete estimate of quantities can not be provided.

The value of these scrap materials was estimated based on recent market prices for bulk scrap. The scrap material prices use for this study were as reported in the March 2008 prices for scrap metal for the Upper Mid-West in the "Demolition Scrap Value and Metal News." The values of scrap quantities utilized in the study are as follows:

- Carbon Steel $230/ton
- Copper $5320/ton

* * * * *

4.0 LIMITATIONS

In preparation of this Asset Demolition Study, B&McD has relied upon information provided by NIPSCO. The information provided by NIPSCO included site and equipment drawings, asbestos remediation estimates prepared by their asbestos contractor Insulco, historic contamination associated with Solid Waste Management Units, and general discussions of the plants during site visits. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of demolition costs are based on Engineer's experience, qualifications and judgment. Weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors at the time of demolition will affect the accuracy of the estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

* * * * *

APPENDIX A – DEMOLITION COST BREAKDOWN

Petitioner's Exhibit VFR-6
Northern Indiana Public Service Company
Cause No. 43526

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TABLE A.1

MICHIGAN CITY UNITS 2 AND 3
DEMOLITION COST BREAKDOWN
OPTION 1 - EQUIPMENT DEMOLITION, BUILDINGS REMAIN

Activities Performed for Demolition of Units 2 & 3 with the Building to Remain

Task		Description	Costs	Credits
1		Environmental Remediation	$7,406,290	$0
2		Major Equipment Removal		
	c	Boilers Demolition	$2,443,152	$0
	d	Turbine and Condenser Removal	$351,584	$0
	e	Chimney Demolition	$229,930	$0
	f	Precipitator Demolition	$686,811	$0
3		Plant Mechanical Systems		
	a	Coal Conveying Equipment Demolition	$681,956	$0
	b	Ash Handling Equipment Demolition	$202,359	$0
	c	Miscellaneous Piping and Hanger Demolition	$942,996	$0
4		Plant Electrical Systems		
	a	Transformer Removal	$68,372	$0
	b	Electrical Equipment Demolition	$378,441	$0
	c	Electrical Controls Demolition	$453,822	$0
	d	Miscellaneous Wiring and Buswork Demolition	$175,492	$0
5		Scrap Value		
	a	Steel	$0	($942,050)
	b	Copper	$0	($7,980)
6		Relocations		
	a	Tuckpointing exterior brick walls; install panels on exterior brick walls that can not be repaired; install temporary removal openings and install panels to cover openings	$564,344	$0

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TABLE A.1

MICHIGAN CITY UNITS 2 AND 3
DEMOLITION COST BREAKDOWN
OPTION 1 - EQUIPMENT DEMOLITION, BUILDINGS REMAIN

Activities Performed for Demolition of Units 2 & 3 with the Building to Remain

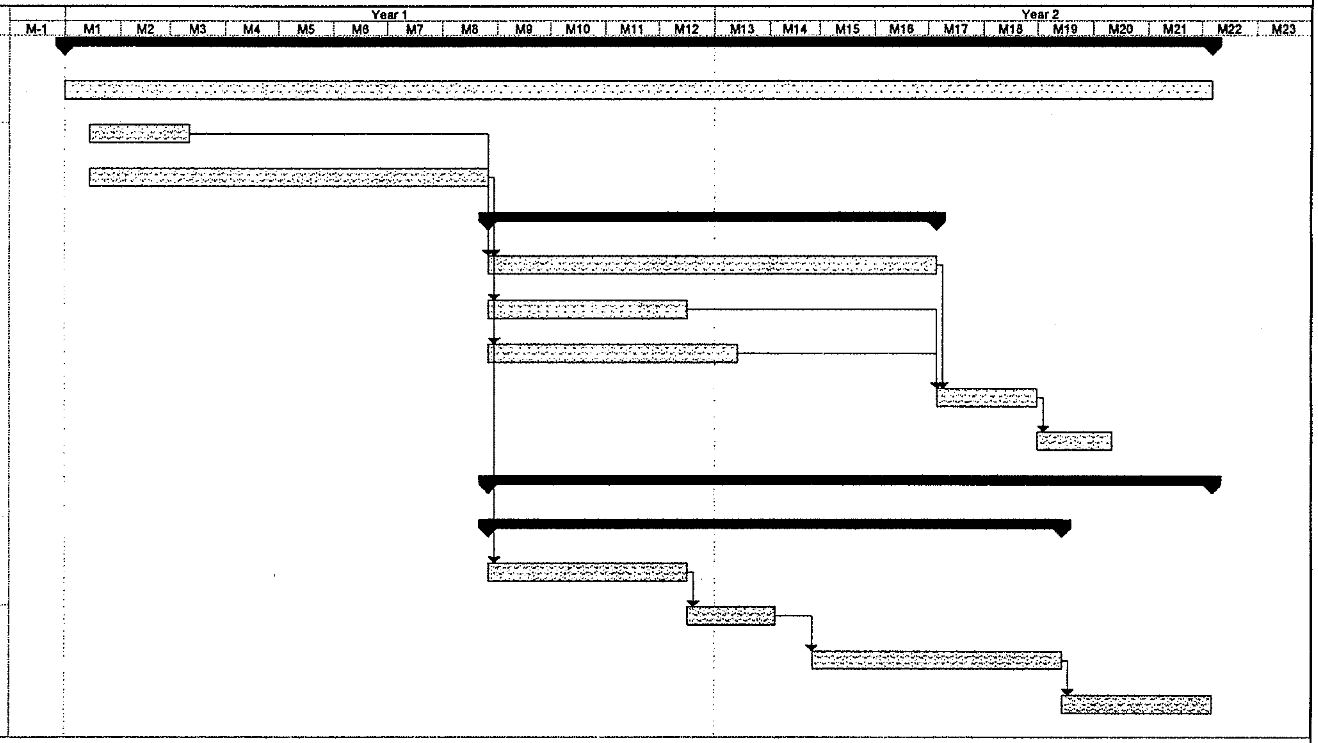
Task Description	Costs	Credits
TOTAL COST (CREDIT)	**$14,586,000**	**($950,000)**
PROJECT INDIRECTS		
Contractor Indirects 5% of Total Cost	$729,000	
Engineering	$438,000	
Construction Management	$292,000	
Owner Indirects	$583,000	
Performance Bond	$305,000	
CONTINGENCY (20%)	$2,917,000	
TOTAL PROJECT COST (CREDIT)	**$19,850,000**	**($950,000)**
TOTAL NET PROJECT COST (CREDIT)	**$18,900,000**	

APPENDIX B – DEMOLITION SCHEDULE

Petitioner's Exhibit VFR-6
Northern Indiana Public Service Company
Cause No. 43526

MICHIGAN CITY UNITS 2 & 3
DEMOLITION SCHEDULE
OPTION 1 - EQUIPMENT DEMOLITION, BUILDINGS REMAIN

ID	Task Name
1	DEMOLITION
2	NIPSCO SITE REPRESENTATIVE
3	NIPSCO DEMOLITION CONTRACTOR AWARD
4	ASBESTOS CONTRACTOR MOB, SITE WORK, DEMOB
5	EQUIPMENT DEMOLITION
6	MAJOR EQUIPMENT
7	PLANT MECHANICAL SYSTEMS
8	PLANT ELECTRICAL SYSTEMS
9	REPAIR BUILDING SHELL / CLOSE ACCESS OPENINGS
10	SITE RESTORATION & CLEANUP
11	MICHIGAN CITY ESSENTIAL SERVICES RELOCATION
12	NEW SHOP, MAINTENANCE AND STOREROOM BUILDING
13	PERMITTING, ENGINEERING AND DESIGN
14	BID, EVAL & AWARD BUILDING CONTRACT
15	INSTALLATION OF BUILDING
16	RELOCATE SERVICES



Project: NIPSCO DEMOLITION - MICI
Date: Tue 5/20/08

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External Milestone | Deadline

Report on the

Asset Demolition Study
Michigan City Unit 2 & 3 Building, Unit 12, and Balance of Plant

for

Northern Indiana Public Service Company
Valparaiso, Indiana

Project Number 48492

June 20, 2008

Burns & McDonnell
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Petitioner's Exhibit VFR-7
Northern Indiana Public Service Company
Cause No. 43526

Asset Demolition Study
Michigan City Unit 2 & 3 Building, Unit 12, and Balance of Plant

prepared for

Northern Indiana Public Service Company
Valparaiso, Indiana

June 20, 2008

Project No. 48492

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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Asset Demolition Study
Michigan City Unit 2 & 3 Building, Unit 12, and Balance of Plant

Project 48492

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APPENDIX A – DEMOLITION COST BREAKDOWNS

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A.1 Demolition Cost Breakdown: Option 1 – Full Demolition, Industrial Site
A.2 Demolition Cost Breakdown: Option 2 – Full Demolition, Greenfield Site

* * * * *

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Burns & McDonnell (B&McD) was retained by Northern Indiana Public Service Company to conduct an Asset Demolition Study of the Michigan City Unit 2 & 3 Building, Unit 12, and Balance of Plant (Plant). The purpose of the Asset Demolition Study was to review the Plant facilities and to provide an estimate to NIPSCO regarding the total cost of complete demolition of the Units. The following report documents our efforts on this study.

Michigan City Unit 12 is a coal-fired unit consisting of a boiler and steam turbine/generator rated at 469 MW. The Plant proper is located on Lake Michigan and includes a water intake and discharge structure for cooling water.

1.2 RESULTS

When NIPSCO determines that the Plant facilities should be demolished, the above grade equipment and steel structures are assumed to have significant scrap value to a salvage contractor. The scrap value of these items will be used as a credit against the demolition costs. However, NIPSCO will incur costs in the restoration of the site following the removal of salvageable equipment.

The asset demolition costs were developed for two scenarios. The first scenario was based on leaving the site in an industrial condition, with below grade foundations and structures remaining on-site, and an on-site inert waste landfill. The second scenario was based on returning the site to a greenfield condition with no structures remaining, compatible with the surrounding land, similar to the conditions that existed before development of the Plant.

Based on the results of the Asset Demolition Study conducted for the Michigan City Generating Station, the estimated demolition costs in current dollars (2008 $) are summarized in Table 1.1 below.

Table 1.1

Demolition Cost Estimate Summary

Option	Total Cost	Project Duration
Full Demolition, Industrial Site	$ 34,509,000	24 Months
Full Demolition, Greenfield Site	$ 64,591,000	30 Months

* * * * *

2.0 PLANT SITE

2.1 SITE VISIT

Representatives from B&McD visited the Plant on March 19, 2008. The purpose of the site visit was to gather information to conduct the Asset Demolition Study, interview the Plant management and operations staff, and to conduct an on-site review of the Plant facilities. The following B&McD representatives comprised the Asset Demolition Study team:

- Mr. Vic Ranalletta, Engineering Manager, Mechanical Engineer
- Mr. Tim Sobieraj, Structural Engineer
- Mr. Gary Herlitz , Electrical Engineer
- Mr. Jeff Pope, Environmental Engineer
- Mr. Jeff Grubich, Environmental Engineer

2.2 PLANT DESCRIPTION

Michigan City Generating Station Unit 12 is a coal-fired unit consisting of a boiler and steam turbine/generator rated at 469 MW. The coal-fired boiler and steam turbine/generator are housed in a metal sided boiler and turbine building. The Unit 12 boiler has an electrostatic precipitator (ESP), a selective catalytic reduction (SCR) system, dry urea unloading and storage, fly ash silo and ash truck loading building, and a concrete stack.

Several levels of concrete structure exist below the turbine floor where ancillary equipment for the Units resides. The turbine or operating floor for each Unit is two levels above the natural grade elevation. The structure houses the surface condensers, condensate pumps, and other ancillary equipment and systems for the Units, auxiliary transformers, motor control centers (MCCs) and switchgear.

Coal is delivered to the Plant by rail cars indexed by a car indexer through a thaw shed into a rotary car unloader. Coal is reclaimed from below the unloader and conveyed to a transfer house where the coal either is directed to a radial stacker out to an open coal pile, or to the coal crusher house. A series of conveyors and transfer houses move crushed coal to the tripper conveyors located above the coal bunkers located between the boiler and turbine room. For purposes of this study, the conveyors interconnecting the main coal handling system serving Unit 12 with the Unit 2 & 3 coal handling system are included in this estimate. For purposes of this study, the demolition of the abandoned underground coal unloading hopper and reclaim conveyor / tunnel serving Units 2 & 3 is included in this estimate.

Bottom ash from the boilers is sluiced to primary ponds located west of the main plant. Ash pond water cascades to secondary ponds for further settling of the suspended ash particles. A water recycling pump house located adjacent to the secondary ponds pump water back to the Plant's ash conveying systems.

A stand-alone, concrete natural draft cooling tower provides the thermal cycle cooling for the Unit. The circulating water pumps and electrical switchgear are located remote from the tower basin in a separate pump and chemical injection building located north of the powerhouse. Underground circulating water pipes extend between the towers and the pump house and the Unit.

Makeup water for cooling and process water needs for Unit 12 is supplied from the Trail Creek intake. Outfall from the tower blowdown, ash pond overflow, and other treated water discharges are to Lake Michigan.

The Plant includes on-site demineralized and condensate water tanks, ash settling basins, and ash ponds with recycle water pump houses.

Electrical energy generated in the Plant is transmitted through a unit generator step up (GSU) transformer to isolated phase bus ducts connected to a high voltage transmission substation. The Plant is back fed electrical energy from the substation through the isolated phase bus ducts connected to the Station auxiliary transformer. The substation includes a control house that contains the control relaying, batteries, SCADA and other support systems.

* * * * *

3.0 SITE DEMOLITION

Two separate cost estimates were prepared for different site demolition scenarios. The first option evaluated included removal of all above grade equipment, piping, and wiring relating at the site, including the buildings, but leaving the foundations and below grade piping and wiring in-place, to return the area to an industrial site. The second scenario included removal of all above grade equipment, piping, wiring at the site, including the buildings, foundations and below grade piping and wiring, to return the area to a greenfield site. A breakdown of each of the demolition cost estimates is provided in Appendix A.

3.1 OPTION 1 – FULL DEMOLITION, INDUSTRIAL SITE

This Option includes removing all equipment at the site, as well as the building structure, but leaving the foundations and below grade piping and wiring in place. All asbestos will be removed, as well as any PCBs, and mercury. The equipment will then be removed and the building demolished. The foundations will remain in place, and the subgrade structure will be used as a repository for inert demolition debris. Underground piping will be capped and abandoned in-place and underground wiring and busduct will be abandoned in-place.

The estimated cost for this demolition option is $34,509,000.

3.1.1 General Cost Assumptions and Clarifications

The following items are included in the cost estimate:

- All estimates are budgetary in nature and do not reflect guaranteed costs.
- All estimates are based on union labor.
- Sufficient area to receive, assemble and temporarily store equipment and materials is available.
- All cost estimates are in current 2008 dollars.
- The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition, therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap at the time of site demolition.
- This option assumes that the Unit 2 & 3 equipment, piping, electrical, and mechanical systems have been previously removed, but the Unit 2 & 3 building and Unit 12 supporting facilities remain. Services required to operate Unit 12 were retained in-place and functional subsequent to Unit 2 & 3 equipment removal, which includes the office area, storeroom, maintenance shops, and Unit 12

supporting utilities. The costs of demolition of the above grade remaining Unit 2 & 3 structures and Unit 12 supporting facilities are included in this option. Also, the Unit 2 & 3 subgrade vault structure is used as an additional on-site inert waste landfill under this option.

- All oils must be confirmed to be non-PCB. If any PCB's are discovered, they will be disposed of properly. Concrete pads and/or flooring surrounding internal transformers will be removed and properly disposed.
- Impacted soils surrounding exterior transformers will be removed to approximately 3 feet below ground surface and disposed of properly.
- All asbestos-based materials will be removed and disposed of in accordance with EPA and OSHA regulations. Transite wall paneling, floor tile, ceiling tile and all other asbestos-containing materials will be removed from all structures and disposed of off-site in accordance with state regulations. The costs include scaffolding necessary to complete the work.
- Batteries, including lead and nickel cadmium batteries will be removed and recycled or disposed of properly. Concrete flooring in battery rooms will be removed and properly disposed.
- Mercury filled equipment and instruments will be removed and disposed of or recycled. Other materials including flooring will be separated from the demolition debris and disposed of properly. Mercury impacted electrical equipment in control rooms will be disposed of properly.
- Freon will be removed and disposed of properly.
- All environmental related costs were obtained through data and information collected during site visits and discussions with NIPSCO operations and NIPSCO environmental employees. NIPSCO environmental costs were used for the historic contamination associated with Solid Waste Management Units (SWMUs). These costs were reviewed and professional judgment was made to ensure that the costs were reasonable and appropriate.
- All waste products such as solvents and oils located in maintenance facilities will be removed and properly disposed. In addition, concrete flooring and impacted soils will be removed and properly disposed.
- OSHA HAZWOPER-trained construction workers will be used to remove arsenic-coated steel in boilers.
- OSHA HAZWOPER-trained construction workers will be used to remove lead-based paint coated steel.
- Gauges containing low-level radioactive materials will be removed and disposed of properly.

- Above grade piping and all tanks will be removed and disposed of properly. Petroleum impacted soils associated with oil piping and both aboveground and underground storage tanks will be removed and disposed of properly.
- All above grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished to grade.
- All above grade plant structures will be demolished to grade. All other building and structure materials such as elevated concrete floors, concrete pedestals above grade, fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc., will be disposed of in the on-site inert waste landfill where possible.
- An on-site inert waste landfill will be utilized for demolition debris consisting of brick, block, concrete and any other materials that fall under the inert waste category. The vault structure beneath the steam turbine generators will serve as the primary location for the inert waste landfill.
- The ground level concrete slab and structural steel framing around the steam turbine generator foundations will be removed. A temporary fence will be placed around the open vault until the vault is filled to grade with inert waste material from demolition operations and soil filled. This will serve as the on-site inert debris landfill.
- Onsite solid waste management units will be properly remediated under RCRA as part of this option.
- All coal in storage will be burned prior to decommissioning.
- The coal handling and storage area will be capped with 1 foot of soil material and seeded. Sufficient on-site material for capping is not available at the Michigan City facility, therefore, off-site material will be used for capping the coal handling and storage area.
- Water will be drained from the coal pile runoff pond located east of the coal yard. Sludge and contaminated soil will be stabilized, excavated, and disposed of at an off-site landfill as a hazardous material.
- The coal storage yard will be covered with topsoil, graded for drainage and seeded. Vegetation will be re-established in the coal pile runoff pond, and it will function as a stormwater runoff surge pond for the coal yard area.
- Openings in the coal unloading and reclaim hopper structures will be sealed with concrete and covered with three feet of fill above existing grade after equipment is removed and drains plugged.
- The above ground conveyors and structures, stacking tubes, transfer houses, conveyor tunnel portals, and crusher house will be demolished. To the extent practical, structural steel and conveyor components will be scrapped. All other building materials, i.e. concrete, brick, etc., will be disposed of in the on-site inert waste landfill where possible.

- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly.
- Ash storage silos/structures, ash piping, pipe racks, and associated equipment will be demolished to grade and scrapped. The exposed foundations will be covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- All remaining plant structures and yard buildings will be demolished. Building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in the on-site inert waste landfill where possible.
- Below grade foundations and ground floor slabs will be left in place and covered with a minimum of three feet of fill above existing grade, graded for drainage, and seeded.
- Underground piping systems will be purged of all oils or chemicals other than water, excavated and disposed of properly.
- Trail Creek intake will be removed and scrapped.
- The outfall structure will be capped with concrete and covered with materials required to restore the original lake bankline. The remaining river intake structure will be filled with materials approved by the US Army Corps of Engineers and covered to restore the original creek bankline.
- All portable tanks will be removed from the site, including any propane tanks, oil storage tanks, chemical totes and waste oil tanks.
- All chemicals will be consumed prior to shut down or disposed of properly, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
- All trash debris and miscellaneous waste will be removed and disposed of properly.
- Water will be drained from all on-site ash and settling ponds. Berm material will be graded into the ponds prior to capping. The ash ponds will be covered with 6 inches of soil followed by a low permeability geomembrane liner overlaid with a final protective vegetative cover of 2 feet of soil, which will be graded for drainage, and seeded. The remaining ponds will be covered with a minimum of 2 feet of soil, graded to drain and seeded. On-site material for capping is not available at the Michigan City facility, therefore, off-site material is used for capping.
- Groundwater monitoring wells will be installed for the closed ponds.
- Equipment spare parts will be removed and sold.
- Plant mobile maintenance equipment and shop maintenance equipment will be removed and salvaged.

- Universal wastes present in office areas that require special handling and disposal such as mercury in fluorescent bulbs and thermostats and PCB contaminated ballasts will be segregated and properly disposed.
- Universal wastes present throughout the remaining areas of the plant that require special handling and disposal such as mercury vapor bulbs and ballasts and fluorescent lighting bulbs and ballasts will be segregated and properly disposed.

3.1.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing
- Escalation
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition
- Transmission or distribution (non-generation) substation modifications or relocation.

3.2 OPTION 2 – FULL DEMOLITION, GREENFIELD SITE

This option includes returning the plant to a Greenfield site condition. Under this scenario, an on-site inert debris landfill would not be used. This cost estimate would include the additional costs associated with hauling all demolition debris off site and also removing below grade foundations, equipment and structures. All underground piping and duct bank would be excavated and removed as well.

The estimated cost for this demolition option is $64,591,000.

3.2.1 General Cost Assumptions and Clarifications

The following items are included in the greenfield cost estimate in addition to or replacement of the assumptions stated for the industrial site closure:

- This option assumes that the Unit 2 & 3 equipment, piping, electrical, and mechanical systems have been previously removed, but the Unit 2 & 3 building and Unit 12 supporting facilities remain. Services required to operate Unit 12 were retained in-place and functional subsequent to Unit 2 & 3 equipment removal, which includes the office area, storeroom, maintenance shops, and Unit 12 supporting utilities. The costs of demolition of the above grade and below grade remaining Unit 2 & 3 structures and Unit 12 supporting facilities are included in this option.

- Impacted soils surrounding exterior transformers will be removed to approximately 10 feet below ground surface and disposed of properly.
- Below grade piping and all tanks will be removed and disposed of properly.
- All below grade piping, pipe supports, and pipe racks will be demolished and scrapped.
- All chimneys will be demolished including subsurface structures.
- All above grade plant structures will be demolished including subsurface structures. Building and structure materials such as elevated concrete floors, concrete pedestals above grade, subsurface structures, fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable tray, etc., will be disposed of in an off-site landfill.
- A total of 1 foot of material in the coal handling and storage areas will be removed and disposed of at an off-site landfill as a hazardous material. One foot of offsite material will be brought to the facility to replace the material removed and revegetated.
- Rail, ties, and ballast from the rail loop will be removed and salvaged, scrapped, or disposed of properly. Impacted soil surrounding the rail lines will be excavated to approximately 1 foot below ground surface and properly disposed.
- All remaining plant structures and yard buildings will be demolished. All building materials, such as elevated concrete floors, roofing and roof deck, concrete pedestals or foundations above grade, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, and cable tray will be disposed of in an off-site landfill.
- Below grade foundations and ground floor slabs will be demolished and the debris disposed of in an off site landfill.
- The entire river intake and outfall structures will be demolished and the debris disposed of in an off site landfill. After removal of the river intake and outfall structures, the areas will be covered with materials required to restore the original river bank line.
- All fixed equipment and below-grade storage vessels will be removed from the site.

3.2.2 Exclusions

The following items are not included in the cost estimate:

- Owner's corporate staffing

- Escalations
- Sales Tax
- All rolling stock (tractors, end loaders, cranes, etc.) will be removed by Owner prior to demolition
- All chemicals, oils, solid fuel, and solid waste will be removed by Owner from above ground structures and operating pits/sumps prior to demolition

3.3 BULK SCRAP MATERIAL VALUE

Burns & McDonnell estimated the quantity of some bulk scrap materials that could be used to offset demolition costs. However, due to the complexity of a power plant and the scope of this study, a complete estimate of quantities can not be provided.

The value of these scrap materials was estimated based on recent market prices for bulk scrap. The scrap material prices use for this study were as reported in the March 2008 prices for scrap metal for the Upper Mid-West in the "Demolition Scrap Value and Metal News." The values of scrap quantities utilized in the study are as follows:

- Carbon Steel $230/ton
- Copper $5320/ton

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4.0 LIMITATIONS

In preparation of this Asset Demolition Study, B&McD has relied upon information provided by NIPSCO. The information provided by NIPSCO included site and equipment drawings, asbestos remediation estimates prepared by their asbestos contractor Insulco, historic contamination associated with Solid Waste Management Units, and general discussions of the plants during site visits. While we have no reason to believe that the information provided to us, and upon which we have relied, is inaccurate or incomplete in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of demolition costs are based on Engineer's experience, qualifications and judgment. Weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors at the time of demolition will affect the accuracy of the estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

* * * * *

APPENDIX A – DEMOLITION COST BREAKDOWNS

Petitioner's Exhibit VFR-7
Northern Indiana Public Service Company
Cause No. 43526

Burns & McDonnell
SINCE 1898

TABLE A.1

MICHIGAN CITY UNIT 2/3 BUILDING, UNIT 12 AND BALANCE OF PLANT DEMOLITION COST BREAKDOWN OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Unit 2/3 Building, Unit 12 & Balance of Plant to Industrial Site

Task	Description	Costs	Credits
1	Environmental Remediation	$14,667,806	$0
2	Building Concrete Removal - Above Grade	$1,496,103	$0
3	Building Structural Steel Removal - Above Grade	$2,639,492	$0
4	Major Equipment Removal		
	a Boilers Demolition	$1,919,936	$0
	b Turbine and Condenser Removal	$374,464	$0
	c Chimney Demolition	$473,848	$0
	d Precipitator Demolition	$255,179	$0
	e SCR Demolition	$281,179	$0
	f Cooling Tower Demolition	$297,472	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$414,488	$0
	b Ash Handling Equipment Demolition	$86,025	$0
	c Miscellaneous Mechanical Equipment Demolition	$797,397	$0
	d Miscellaneous Piping and Hanger Demolition	$445,531	$0
6	Plant Electrical Systems		
	a Transformer Removal	$37,448	$0
	b Electrical Equipment Demolition	$730,285	$0
	c Electrical Controls Demolition	$216,699	$0
	d Miscellaneous Wiring and Buswork Demolition	$417,797	$0

Burns & McDonnell
SINCE 1898

TABLE A.1

MICHIGAN CITY UNIT 2/3 BUILDING, UNIT 12 AND BALANCE OF PLANT DEMOLITION COST BREAKDOWN OPTION 1 - FULL DEMOLITION, INDUSTRIAL SITE

Activities Performed for Demolition of Unit 2/3 Building, Unit 12 & Balance of Plant to Industrial Site

Task	Description	Costs	Credits
7	Credit for filling in Unit 12 Turbine, Boiler, and Service Building Foundations	$0	($2,310,338)
8	Scrap Value - Unit 12 & Balance of Plant		
	a Steel	$0	($2,905,928)
	b Copper	$0	($32,253)
	c Equipment	$0	($1,434,314)
9	Units 2 & 3 Building Above Grade (Equipment Removal Not Included)	$10,952,244	$0
10	Scrap Value - Unit 2 & 3		
	a Steel	$0	($3,133,526)
11	Credit for filling in Unit 2 & 3 Turbine, Boiler, Admin, and Service Building Foundations	$0	($3,470,125)
	a Surplus material for filling ponds, etc...	$0	($509,236)
TOTAL COST (CREDIT)		**$36,503,000**	**$ (13,796,000)**
PROJECT INDIRECTS			
	Contractor Indirects 5% of Total Cost	$1,825,000	
	Engineering	$548,000	
	Construction Management	$538,000	
	Owner Indirects	$730,000	
	Performance Bond	$860,000	
CONTINGENCY (20%)		$7,301,000	
TOTAL PROJECT COST (CREDIT)		**$48,305,000**	**($13,796,000)**
TOTAL NET PROJECT COST (CREDIT)		**$34,509,000**	

Burns & McDonnell
SINCE 1898

TABLE A.2

MICHIGAN CITY UNIT 2/3 BUILDING, UNIT 12 AND BALANCE OF PLANT DEMOLITION COST BREAKDOWN OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Unit 2/3 Building, Unit 12 & Balance of Plant to Greenfield

Task	Description	Costs	Credits
1	Environmental Remediation	$21,173,552	$0
2	Building Concrete Removal - Above Grade	$1,496,103	$0
3	Building Structural Steel Removal - Above Grade	$1,847,136	$0
4	Major Equipment Removal		
	a Boilers Demolition	$1,919,936	$0
	b Turbine and Condenser Removal	$374,464	$0
	c Chimney Demolition	$473,848	$0
	d Precipitator Demolition	$255,179	$0
	e SCR Demolition	$281,179	$0
	f Cooling Tower Demolition	$297,472	$0
5	Plant Mechanical Systems		
	a Coal Conveying Equipment Demolition	$414,488	$0
	b Ash Handling Equipment Demolition	$86,025	$0
	c Miscellaneous Mechanical Equipment Demolition	$797,397	$0
	d Miscellaneous Piping and Hanger Demolition	$445,531	$0
6	Plant Electrical Systems		
	a Transformer Removal	$37,448	$0
	b Electrical Equipment Demolition	$730,285	$0
	c Electrical Controls Demolition	$216,699	$0
	d Miscellaneous Wiring and Buswork Demolition	$417,797	$0
7	Below Grade Demolition		
	a Boiler Building	$1,767,496	$0
	b Turbine Building	$1,351,187	$0
	c Balance of Plant Buildings	$3,722,028	$0
	d Circulating Water Pipe Demolition	$43,948	$0

Petitioner's Exhibit VFR-7
Northern Indiana Public Service Company
Cause No. 43526

Burns & McDonnell
SINCE 1898

TABLE A.2

MICHIGAN CITY UNIT 2/3 BUILDING, UNIT 12 AND BALANCE OF PLANT DEMOLITION COST BREAKDOWN OPTION 2 - FULL DEMOLITION, GREENFIELD SITE

Activities Performed for Demolition of Unit 2/3 Building, Unit 12 & Balance of Plant to Greenfield

Task	Description	Costs	Credits
	e Below Grade Other Piping Demolition	$57,381	$0
	f Below Grade Busduct Demolition	$43,688	$0
8	Scrap Value		
	a Steel	$0	($2,913,506)
	b Copper	$0	($42,104)
	c Equipment	$0	($1,780,980)
9	Site Restoration	$1,831,600	$0
10	Units 2 & 3 Building Above Grade (Equipment Removal Not Included)	$10,952,244	$0
11	Units 2 & 3 Building Below Grade (Equipment Removal Not Included)	$4,206,127	
12	Scrap Value - Unit 2 & 3		
	a Steel	$0	($3,243,926)
TOTAL COST (CREDIT)		**$55,240,000**	**$ (7,981,000)**
PROJECT INDIRECTS			
	Contractor Indirects 5% of Total Cost	$2,762,000	
	Engineering	$829,000	
	Construction Management	$538,000	
	Owner Indirects	$1,105,000	
	Performance Bond	$1,050,000	
CONTINGENCY (20%)		$11,048,000	
TOTAL PROJECT COST (CREDIT)		**$72,572,000**	**($7,981,000)**
TOTAL NET PROJECT COST (CREDIT)		**$64,591,000**	

Petitioner's Exhibit BKS-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

BRADLEY K. SWEET

VICE PRESIDENT
STRATEGIC PLANNING AND OPERATIONS SUPPORT

SPONSORING PETITIONER'S EXHIBIT BKS-2

VERIFIED DIRECT TESTIMONY OF BRADLEY K. SWEET

Q1. Please state your name, job title, employer and business address.

A1. My name is Bradley K. Sweet. I am Vice President, Strategic Planning and Operations Support for the NiSource Inc. Northern Indiana Energy group. I am submitting this testimony on behalf of Northern Indiana Public Service Company ("NIPSCO" or the "Company"). My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410.

Q2. Please summarize your educational background.

A2. I graduated from Michigan Technological University with a Bachelor of Science degree in Electrical Engineering in 1976. I also graduated from the University of Chicago with a Masters of Business Administration in 1995.

Q3. What are your current responsibilities as Vice President, Strategic Planning and Operations Support?

A3. I am responsible for Capacity Planning/Integrated Resource Planning ("IRP") Development and Northern Indiana Energy Strategic Planning

Q4. Please describe your professional experience.

A4. I began my employment with NIPSCO in May 1977 as an Electrical Engineer in the Plant Engineering Department. Since that time, I have held various engineering and management positions. In 1981, I was promoted to Supervisor, Electrical. Between 1981 and 1990, I held various supervisory positions in the Plant Engineering and Construction Department for the different NIPSCO generating stations, including coordination of activities affecting the various boilers, turbines and other special projects. In May 1991, I was promoted to Manager, Power Engineering. In December 1993, I was promoted to Operations and Maintenance ("O&M") Manager at D. H. Mitchell Generating Station ("Mitchell"). In September 1994, I was promoted to Manager, Coal Handling at R. M. Schahfer Generating Station ("Schahfer") and O&M Manager for Units 17 and 18 at Schahfer. Between January 1996 and April 2005, I held various management positions at Schahfer, including positions having general responsibility over coal handling, engineering, maintenance and business planning. I was promoted to Director of Generation Dispatch and Energy Management in May 2005. I assumed my current position, Vice President, Strategic Planning and Operations Support, in July 2008.

Q5. Have you previously testified before this or any other regulatory Commission?

A5. Yes, I routinely testify before this Commission in the Company's Fuel Adjustment Clause ("FAC") (Cause No. 38706-FAC-XX) proceedings. I also testified before this Commission in Cause Nos. 42824, 43393, 43396 and 43471.

Q6. What is the purpose of your testimony in this Cause?

A6. The purpose of my testimony is to describe the effect of NIPSCO's membership in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and various Federal Energy Regulatory Commission ("FERC") orders on NIPSCO's operations. I also discuss NIPSCO's compliance with the Midwest ISO's Resource Adequacy Plan - including a discussion regarding differences in our operations between 2007 and 2008. In addition, I address increases in O&M expenses due to generation re-dispatch, retiring specific generating units at Mitchell and Michigan City and NIPSCO's purchase of the Sugar Creek Generating Station ("Sugar Creek Facility").

Q7. What exhibits are you sponsoring in this proceeding?

A7. I am sponsoring <u>Petitioner's Exhibit BKS-2</u>.

I. <u>NIPSCO'S ELECTRIC TRANSMISSION SYSTEM</u>

A. <u>Evolution to Open Access</u>

(i) History

Q8. Please address the general evolution of NIPSCO's electric transmission system.

A8. The NIPSCO electric transmission system was primarily designed and operated to reliably serve NIPSCO's native load. To meet the needs of its retail customers, electricity generated within the NIPSCO service territory had to be transmitted to customers within the NIPSCO system. The transmission system was largely "self-sufficient" except when internal generation was unable to meet internal demand, at which time power had to be brought into the NIPSCO system (imported) from outside its service territory.

Just as NIPSCO's transmission system was designed to handle the demands of the NIPSCO service territory, the transmission systems of neighboring utilities were designed to handle their internal needs. Agreements between/among neighboring utilities allowed for the transfer of power in those situations where a utility could not meet the needs of its service territory with internal generation for any reason. Although not its primary purpose, these interconnections also allowed economic exchange of power with the neighboring interconnected utilities and contributed to the stability of the interconnection and provided system frequency support.

Then, in 1996, FERC implemented open transmission access through FERC Orders 888[1] and 889,[2] which provided for nondiscriminatory transmission access. Those two orders marked the beginning of a dramatic change to the way in which electric transmission systems, including the NIPSCO system, were used. This change in the intended use of the system has directly impacted operation of the NIPSCO facilities.

B. <u>FERC</u>

Q9. How did the above-referenced FERC Orders change the way utilities use their transmission systems?

A9. With the advent of open transmission access pursuant to FERC Orders 888 and 889, the transmission systems of utilities became a means of transmitting power across service territories and beyond neighboring utilities. Power was transmitted to any other purchasing utility that requested the power on a nondiscriminatory basis, provided the transmission facilities could accommodate the request. As part of this open transmission access, the transmission facilities within the NIPSCO service territory were called upon to move external power across the NIPSCO transmission system as well as the traditional

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[1] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[2] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 61,253 (1997).

flow to load within the NIPSCO service territory. In essence, the transmission infrastructure that was designed by NIPSCO to serve as a well-traveled local access road was pressed into service as an interstate highway.

Q10. Did FERC subsequently issue orders affecting the operation of NIPSCO's transmission system?

A10. Yes. To further FERC's open access initiative, FERC issued Order 2000.[3] In that order, FERC defined the requirements of a Regional Transmission Organization ("RTO"), and strongly encouraged transmission owners to join an RTO. The Order identified eight minimum functions of an RTO:

1. Develop a transmission tariff and administration that will promote efficient use and expansion of transmission and generation facilities.
2. Develop congestion management procedures.
3. Develop and implement loop flow and parallel path procedures.
4. Serve as the provider of last resort for all ancillary services.
5. Operate a single Open-Access Same-Time Information System ("OASIS") for all transmission under its control and be responsible for independently calculating Total Transmission Capacity and Available Transmission Capacity.
6. Monitor markets to measure market power and market design flaws and propose remedies.
7. Plan and coordinate necessary transmission upgrades and additions, including coordinating its efforts with State regulators.

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[3] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Util. Dist. No. 1 v. FERC*, 272 F.3d 607, (D.C. Cir. 2001) ORDER, ("Order 2000").

8. Develop mechanisms to coordinate its activities with other regions, whether or not an RTO exists in those regions, especially concerning reliability and market interfaces.

These requirements have affected the operation of NIPSCO's transmission system.

C. Midwest ISO

Q11. Did NIPSCO join an RTO?

A11. Yes. As of October 1, 2003, NIPSCO transferred functional control of its transmission operations to the Midwest ISO pursuant to the September 24, 2003 Indiana Utility Regulatory Commission's Order in Cause No. 42349. Effective with that transfer, the Company began taking network transmission service under the Midwest ISO Open Access Transmission Tariff ("OATT") to serve its Indiana retail electric customers. Power continued to flow across the NIPSCO transmission facilities with Midwest ISO providing transmission service.

II. MIDWEST ISO'S RESOURCE ADEQUACY PLAN

Q12. Are you familiar with the evolution of the Midwest ISO's long-term Resource Adequacy Plan?

A12. Yes. When FERC conditionally approved Midwest ISO's Open Access Transmission and Energy Markets Tariff ("TEMT") on August 6, 2004, it also approved the proposed Module E of the TEMT as a "short-term transition mechanism" to help ensure reliability throughout the Midwest ISO footprint. In the same order, FERC directed the Midwest ISO to work toward a long-term resource adequacy plan through its stakeholder process.[4]

In response to that directive, on December 28, 2007, the Midwest ISO filed its long-term resource adequacy proposal. The proposal contains mandatory requirements for any market participant serving load in the Midwest ISO region to have and maintain access to sufficient planning resources. These planning resources include all resources used to meet a resource adequacy requirement, including generation capacity, qualified purchases, and demand response. Under the proposal, the Midwest ISO would establish a Planning Reserve Margin for each Load-Serving Entity ("LSE"). Each LSE must demonstrate that it has sufficient resources to meet the forecast requirements plus the applicable Planning Reserve Margin requirements and may contract with other parties to demonstrate compliance. NIPSCO is an LSE and, therefore, must comply with these requirements.

While FERC approved Midwest ISO's proposal to rely on bilateral procurement of capacity by LSEs, FERC noted that the Midwest ISO will have to perform functions similar to what FERC requires in capacity markets. Those support functions include determining capacity obligations, monitoring compliance, and assessing penalties to deficient LSEs. The first planning year under the Resource Adequacy Plan will start June 1, 2009.

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4 *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 421, *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043, *order on reh'g*, 112 FERC ¶ 61,086 (2005), *aff'd sub nom. Wisc. Pub. Power Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007).

Q13. Are there any resource capacity requirements for the summer of 2008?

A13. Yes. NIPSCO is a member of the Midwest Planning Reserve Sharing Group ("PRSG"), which is a voluntary group of LSEs. The group was established to study the collective resources of the group and to determine a minimum level of planning reserve requirements based upon reliability principles and standards set forth by applicable Reliability Entities.[5] The Midwest PRSG approved a planning reserve target margin for the 2008 – 2009 planning year of 14.3% for the Central Zone, of which NIPSCO is a member.

Q14. How does NIPSCO intend to meet its 2008 – 2009 planning reserve target margin?

A14. NIPSCO has purchased 800 MWs of capacity for the period June 1, 2008 through May 31, 2009. NIPSCO has entered into seven contracts of between 50 and 200 MWs each for a total price of under $14,000,000.

Q15. How does NIPSCO propose to recover these costs?

A15. The Company seeks recovery of its 2009 capacity costs through the Reliability Adjustment mechanism described by NIPSCO Witness Curtis L. Crum.

III. NIPSCO'S INTERNAL GENERATION

Q16. Are you generally familiar with NIPSCO's generating facilities?

A16. Yes, I am.

[5] The term used by the North American Electric Reliability Corporation ("NERC") which applies to an organization that is responsible for carrying out the Tasks within a Function. Responsible Entities are registered by the Electric Reliability Organization (ERO) and maintained in its registry as described in the ERO Rules of Procedure and ERO Delegation Agreements.

Q17. Please generally describe NIPSCO's generation fleet.

A17. The NIPSCO generating facilities have a total capacity of 2,787 megawatts ("MW") and consist of six (6) separate generation sites, including Schahfer, Michigan City Generating Station, Bailly Generating Station, Mitchell, and Norway and Oakdale hydroelectric facilities, which are described in more detail by NIPSCO Witness Philip W. Pack. The total MWs exclude the Sugar Creek Facility, which is discussed later.

Q18. Is NIPSCO planning to retire any of its generation facilities in the near future?

A18. Yes. NIPSCO plans to retire Units 4, 5, 6, 9A, and 11 at Mitchell and Units 2 and 3 at Michigan City.

Q19. Why is NIPSCO retiring Mitchell Units 4, 5, 6 and 11?

A19. Those Units were indefinitely shutdown about January 2002. NIPSCO has continued to evaluate the Mitchell Units as recently as its 2007 IRP. NIPSCO has concluded that restarting the Mitchell Units, compared to the alternatives in the 2007 IRP, is not the most effective balance between economics and risk mitigation.

Q20. Why is NIPSCO retiring Unit 9A at Mitchell?

A20. Unit 9A at Mitchell will be retired near the end of the demolition of the other Mitchell Units. The 2007 IRP projected Unit 9A's retirement to be the end of 2016. The retirement as proposed herein would occur a number of years prior to 2016. This retirement is appropriate when the costs of security, monthly testing, and on-going maintenance are considered.

Q21. Did NIPSCO consider restarting the Mitchell Units?

A21. Yes, NIPSCO evaluated the restart of the Mitchell Units as part of its 2007 IRP. However, that analysis showed restarting the Mitchell Units was not the most effective balance between economics and risk mitigation. Because of the New Source Review requirements confirmed by the Indiana Department of Environmental Management ("IDEM"), the 2007 IRP projected the cost to restart the Mitchell Units at $587,500,000 resulting in 443 MW of capacity. A copy of the IDEM letter confirming that New Source Review would be required is attached to my testimony as Petitioner's Exhibit BKS-2.

NIPSCO also studied another option, repowering the Mitchell Units. The Company projected the cost of repowering the Mitchell Units to be $758,500,000. Repowering these units would result in 447.8 MW of capacity. Both of these options, when compared to the alternatives in the 2007 IRP, were not the most effective balance between economics and risk mitigation.

Q22. Why is NIPSCO retiring Michigan City Units 2 and 3?

A22. The Michigan City Units were indefinitely shutdown in June 2005 due to the condition of the boilers. These coal-fired units were placed in-service in 1951, were only fired on natural gas since 1988, and are at the end of their useful life.

Q23. Were there other operational constraints in 2007 that reduced the operating hours of NIPSCO's various generating units?

A23. Yes.

Q24. Please describe those constraints and how run time should be adjusted to reflect normal operating conditions?

A24. As explained by Mr. Pack, Unit 7 was off line to install cyclones between February and May, 2007. This was considered an unplanned outage, as the normal planned maintenance outage was scheduled in the fall of 2007. Run time should be adjusted by an increase of over three months for this unit.

As explained by Mr. Pack, Unit 10 was unavailable for eleven months in 2007. Run time should be adjusted by an increase of eleven months for this unit.

As explained by Mr. Pack, Unit 16A was unavailable for almost five months in 2007 due to a major failure. Run time should be adjusted by an increase of almost five months for this unit.

IV. CAPACITY SOLUTIONS

Q25. Has NIPSCO undertaken any steps to address its need for capacity?

A25. Yes. NIPSCO purchased the Sugar Creek Facility, a 535 MW combined cycle gas turbine generating station located near Terre Haute, Indiana, to provide it with additional capacity and energy. The Sugar Creek Facility is configured with two combustion gas turbines and one steam turbine generator. The Sugar Creek Facility has the ability to interconnect with either the Midwest ISO or the PJM Interconnection, LLC ("PJM").

Q26. Did NIPSCO receive a Certificate of Public Convenience and Necessity ("CPCN") from the Commission prior to acquiring the Sugar Creek Facility?

A26. Yes. The Commission granted NIPSCO a CPCN to acquire the Sugar Creek Facility in its May 28, 2008 Order in Cause No. 43396 (the "CPCN Order"). The CPCN Order found that the purchase price for the Sugar Creek Facility was reasonable and that the acquisition was in the public interest.

Q27. What was the purchase price of the Sugar Creek Facility?

A27. The total purchase price paid by NIPSCO for the Sugar Creek Facility was $329,672,739 as of June 30, 2008, but expects to adjust this purchase price to reflect a post-closing working capital adjustment.

Q28. How did NIPSCO assume ownership of the Sugar Creek Facility?

A28. NIPSCO acquired the equity interests in Sugar Creek Power Company, LLC, (the then owner of the plant) on May 30, 2008. On July 7, 2008, Sugar Creek Power Company, LLC was merged into NIPSCO. Accordingly, the Sugar Creek Facility is now an asset owned directly by NIPSCO.

Q29. Is NIPSCO seeking to include the Sugar Creek Facility as part of its rate base in this proceeding?

A29. Yes. NIPSCO is proposing to do so as part of a second step rate change that would become effective when the Sugar Creek Facility is dispatched into the Midwest ISO.

Q30. Why is NIPSCO proposing a second step rate change to reflect the Sugar Creek Facility?

A30. Although NIPSCO has already acquired the Sugar Creek Facility, the CPCN Order found that the Sugar Creek Facility could not be deemed to be "in service" under Indiana law until it can be dispatched into the Midwest ISO. The prior owner of the Sugar Creek Facility committed its output to the PJM capacity market through May 31, 2010. NIPSCO will dedicate the Sugar Creek Facility to the Midwest ISO after the unit's commitment to PJM expires. NIPSCO is seeking approval to adjust its rates and charges at such time to reflect the in-service status of the Sugar Creek Facility.

Q31. Is NIPSCO also seeking to include additional O&M expenses associated with the Sugar Creek Facility in its second phase rate increase?

A31. Yes. Mr. Pack discusses NIPSCO's costs.

V. <u>TRANSMISSION PLANNING</u>

Q32. Have there been any changes in NIPSCO's transmission planning processes?

A32. Yes. NIPSCO's transmission processes have been modified as a result of the impacts of the Energy Policy Act of 2005 ("EPAct 2005"), which made important changes to improve reliability, promote investment in electric facilities, enhance the nation's electric infrastructure, improve wholesale competition, and promote greater efficiency in electric generation and delivery. FERC is taking action on multiple fronts to enhance the reliability of the electric transmission system. FERC certified NERC as the nation's ERO, which began operation on June 18, 2007.

FERC has issued various orders making NERC reliability standards mandatory and sanctionable. The ERO and the Regional Reliability Organizations must monitor compliance with these reliability standards and may direct violators to comply with the standards and impose penalties for violations, subject to review by and appeal to FERC.

FERC has asserted that the transmission system needs to be expanded and improved to promote wholesale competition and to produce the greatest benefit for all stakeholders from RTO participation.

Q33. Does this conclude your prepared direct testimony?

A33. Yes, it does.

VERIFICATION

I, Bradley K. Sweet, Vice President, Strategic Planning and Operations Support for the NiSource Inc. Northern Indiana Energy group, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Bradley K Sweet

Bradley K. Sweet

Date: August 29 2008

INDS01 DWM 1055325.DOC

Northern Indiana Public Service Company
Cause No. 43526
Petitioner's Exhibit BKS-2

Kec

IDEM INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Mitchell E. Daniels, Jr.
Governor

Thomas W. Easterly
Commissioner

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JUL 16 2007
EH&S DEPT.

July 12, 2007

Mr. Arthur E. Smith, Jr.
Sr. Vice President & Environmental Counsel
Environmental, Health & Safety
NiSource Corporate Services
801 E. 86th Avenue
Merrillville, IN 46410

Dear Mr. Smith:

Re: Intent to Operate Dean H. Mitchell Generating Station–NIPSCO

Thank you for your letters of June 26, 2007 and July 5, 2007 regarding NIPSCO's intent to operate the Dean H. Mitchell Generating Station.

Your June 26, 2007 letter states: "NIPSCO seeks clarification on the steps and circumstances needed to reactivate Mitchell." You further state: "NIPSCO requests that IDEM review and provide comments on the approaches presented in the attached reports[1]."

In summary the Guernsey & Company reports advocate resuming operation of the Mitchell facility without first receiving a preconstruction "New Source Review" air pollution permit, while the Burns & McDonnell report concludes that a preconstruction "New Source Review" air pollution permit is likely to be required.

The different interpretations of the requirements for reactivation are understandable considering the various court decisions that have been issued around the country in response to EPA's Coal Fired Electric Generating Unit New Source Review enforcement initiative which commenced approximately ten years ago. Recent court decisions, including some addressing actions by Indiana sources which had received IDEM permits have clarified the judicial interpretation of parts of the New Source Review Regulations. While there are still a number of issues that have not been fully resolved by the courts, this letter presents IDEM's best current understanding of the New Source Review requirements under the Clean Air Act and the implementing regulations.

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[1] *Economic Evaluation of Alternatives Concerning the Dean H. Mitchell Generating Station*, December 29, 2006, C.H. Guernsey & Company, the January 31, 2007 *addendum* to that report, and Guernsey's February 19, 2007 memorandum titled "*Evaluation of Suggestions to Replace Major Equipment at Mitchell*"; *D.H. Mitchell Reactivation Report* Submitted to Northern Indiana Public Service Co., January 2007, Burns and McDonnell.

For the following reasons, I conclude that the reactivation of the Mitchell Plant will require a preconstruction New Source Review permit:

1. The facility is presumed to be permanently shut down under EPA's September 6, 1978 Memorandum from Edward E. Reich, Director of Stationary Source Enforcement titled "PSD Requirements." The presumptive shutdown standard in this memorandum has been used as the foundation of EPA policy as recently as the September 7, 2001 letter from Douglas E. Hardesty of EPA Region 10 to Jerald W. Holmes of the Colville Tribal Enterprise Corporation regarding the Startup of Quality Veneer & Lumber Facility. EPA's September 6, 1987 policy states:

   > "A source which had been shut down would be a new source for PSD purposes if the shutdown was permanent. Conversely, it would not be a new source if the shutdown was not permanent. Whether a shutdown was permanent depends upon the intention of the owner or operator at the time of the shutdown as determined from all the facts and circumstances, including the cause of the shutdown and the handling of the shutdown by the State. **A shutdown lasting for two years or** more, or resulting in removal of the source from the emissions inventory of the State, **should be presumed permanent.** The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent and overcoming the presumption that it was."

2. NIPSCO's December 5, 2001 press release is titled "NIPSCO announces shutdown of Dean H. Mitchell Generating Station." The press release further characterized the plans to "indefinitely shut down its Dean H. Mitchell Generating Station....This decision is based on ....and the significant cost required to maintain the aging facility."
3. The substantial investment required to make the facility operable (estimated to be at least $35,000,000 without environmental considerations) along with the nature of the investments (i.e. Unit 4 economizer replacement, Unit 6 Primary Superheat Replacement, Units 6 & 11 Precipitator replacements) do not appear to fall within the "routine maintenance repair and replacement exclusion" as that exclusion is interpreted by the United States District Court, Southern District of Indiana in its June 18, 2007 "Order on Motions for Partial Summary Judgment Regarding the Application of the Routine Maintenance Repair and Replacement Exclusion at Beckjord, Cayuga, Gallagher, Gibson, and Miami Fort Plants.[2]" That decision evaluated a number of projects for: nature and extent, purpose, frequency, and cost. For each project evaluated, the court determined that projects which appear to be similar in scope to the proposed work to restart the Mitchell facility were not covered by the routine maintenance repair and replacement exclusion. In addition, the program of testing and replacing boiler tubes with limited wall thickness outlined in the Guernsey report may also exceed the scope of the routine maintenance repair and replacement exclusion.
4. Since the facility has not operated for the past 5 years, its past actual emissions are zero, so if the restarted facility emits more than 15 tons of PM_{10}, 40 tons of VOC, NO_x, or SO_2, 100 tons of CO, 0.6 tons of lead, or 200 pounds of mercury the restart is a major modification because it will cause a significant emissions increase and it is therefore subject to the new source review requirements.

Lake County Indiana is currently designated as a nonattainment area for Ozone and $PM_{2.5}$. Therefore, the facility will need to incorporate "Lowest Achievable Emission Rate" technology

[2] U. S. v. Cinergy Corp.; United States District Court, Southern District Indiana, Case 1:99-cv-01693-LJM-JMS (Order issued by Judge Larry J. McKinney, June 18, 2007).

and obtain emissions offsets from existing sources for VOC, NO_x, and PM_{10}. The facility will need to install Best Available Control Technology for SO_2 and possibly mercury and lead.

In addition, the source will need to meet its obligations under Indiana's Clean Air Interstate Rule which limits NO_x and SO_2 and the Clean Air Mercury Rule which limits mercury.

If you would like to proceed in accordance with this letter, IDEM is required (and is able to) issue the appropriate NSR permit within 270 days of receipt of a complete application which includes acceptable LAER and BACT emission control proposals, identification of the emission offsets obtained for the project, air quality modeling for the PSD pollutants and all other required information.

If you have any questions about this letter, please contact me at (317) 232-8611.

Sincerely,

Thomas W. Easterly
Commissioner

Petitioner's Exhibit CLC-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

CURTIS L. CRUM

DIRECTOR, GENERATION DISPATCH AND ENERGY MANAGEMENT

VERIFIED DIRECT TESTIMONY OF CURTIS L. CRUM

Q1. Please state your name, job title, employer and business address.

A1. My name is Curtis L Crum. I am the Director, Generation Dispatch and Energy Management for Northern Indiana Public Service Company ("NIPSCO" or "Company"). My business address is 1500 165th Street, Hammond, Indiana 46320.

Q2. Please summarize your educational background.

A2. I graduated in 1982 from Purdue University with a Bachelors Degree in Electrical Engineering. I am also a North American Electric Reliability Corporation ("NERC") Certified System Operator.

Q3. What are your current responsibilities as Director, Generation Dispatch and Energy Management?

A3. I am responsible for the planning and development of electric system power supply requirements and the direction of the operation of NIPSCO's dispatch of generation and resources to meet requirements and system conditions including the coordination of the above with the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). I am also responsible for NIPSCO's oversight of the market settlements of the Midwest ISO's Day 2 energy markets as they pertain to NIPSCO.

Q4. Please describe your professional experience.

A4. I began my employment with NIPSCO in 1981 as a Communications Engineer for four years. I then worked ten years in Distribution Planning, two years as a Transmission Planner, and since then have held various positions in electric system operations. In

2004, I became Manager Market Issues and Strategies within electric system operations. In July 2008 I assumed my current position.

Q5. Have you previously testified before this Commission?

A5. Yes, I testified before this Commission in Cause No. 42685 about the Midwest ISO's uninstructed deviation penalties and in NIPSCO's most recent Fuel Adjustment Clause ("FAC") proceeding (Cause No. 38706-FAC 80).

Q6. What is the purpose of your testimony in this Cause?

A6. The purpose of my testimony is to discuss recovery of certain costs billed to NIPSCO by the Midwest ISO that have been deferred and to describe certain aspects of NIPSCO's rate adjustment mechanism, which is being requested pursuant to Ind. Code § 8-1-2-42(a), and is hereinafter referred to as the Reliability Adjustment ("RA" or "RA Tracker"). The RA provides for the timely recovery of: (1) charges and credits assessed by Regional Transmission Organizations ("RTOs"), including costs associated with transmission upgrades constructed by others ("RTO Costs"); (2) NIPSCO's purchased power costs; (3) NIPSCO's capacity costs; and the allocation of revenues from NIPSCO's off-system sales. NIPSCO Witness Linda E. Miller describes the proposed timing for RA filings and pro-forma schedules for processing the RA Tracker. I also discuss NIPSCO's proposed purchased power benchmark, and NIPSCO's proposed Tariff revisions related to the definitions of "interruption" and "curtailment."

I. <u>RECOVERY OF DEFERRED MIDWEST ISO CHARGES</u>

Q7. What is the history of NIPSCO's participation in the Midwest ISO?

A7. The Midwest ISO was created pursuant to the Agreement of Transmission Facilities Owners to Organize The Midwest Independent Transmission System Operator, Inc. As of October 1, 2003, NIPSCO transferred functional control of its transmission operations to the Midwest ISO pursuant to the Commission's September 24, 2003, Order in Cause No. 42349. At the same time, the Company began taking transmission service under the Midwest ISO Open Access Transmission Tariff ("OATT") to serve its Indiana retail electric customers.

On March 31, 2004, the Midwest ISO filed a proposed Open Access Transmission and Energy Markets Tariff ("Energy Markets Tariff' or "TEMT") with the Federal Energy Regulatory Commission ("FERC") in Docket No. ER04-691-000. The Midwest ISO's Energy Markets Tariff set forth rates, charges, terms and conditions for the implementation of a centralized security-constrained economic dispatch platform supported by a day-ahead and real-time energy market design, including locational marginal pricing ("LMP") and Financial Transmission Rights ("FTRs") within the Midwest ISO region. On May 26, 2004, the FERC directed the Midwest ISO to implement energy markets (also known as "Day 2 energy markets") in the Midwest ISO region on March 1, 2005. The start of the Day 2 energy markets was subsequently delayed to April 1, 2005.

On July 9, 2004, NIPSCO and three other Indiana electric utilities sought Commission approval for their participation in the Day 2 energy markets. On June 1, 2005, the Commission issued its order in Cause No. 42685 approving the transfer of certain utilities' control area operations and their participation in the Day 2 energy markets ("June 1st Order")

Q8. Are you generally familiar with the operations of the Midwest ISO?

A8. Yes. I am actively involved with NIPSCO's Midwest ISO Day 2 operations.

Q9. What are your responsibilities in that regard?

A9. I am responsible for the direction of generation dispatch within the Midwest ISO energy markets, NIPSCO's oversight of the Midwest ISO settlements, and monitoring changes in the Midwest ISO tariffs and operations and their impact on NIPSCO dispatch operations. I am also responsible for the nominations of Auction Revenue Rights/FTRs to serve NIPSCO load and the Meter Data Management Agent functions within the NIPSCO balancing authority for several market participants.

Q10. Please describe the Midwest ISO-related costs incurred by NIPSCO.

A10. NIPSCO's Midwest ISO-related costs can be grouped into three categories: (1) non-fuel charges assessed by the Midwest ISO pursuant to its tariff that have been accepted for filing by FERC; (2) fuel-related costs incurred due to participation in the Midwest ISO pursuant to its tariff that have been accepted for filing by FERC; and (3) transmission costs accessed through Attachment FF and other transmission costs pursuant to rate schedules that have been accepted for filing by FERC.

Q11. Are you familiar with the Commission's June 1st Order regarding recovery of costs associated with NIPSCO's participation in the Midwest ISO?

A11. Yes. The June 1st Order essentially divided all Midwest ISO credits and charges into the following two categories: (1) those items that "should be included in the cost of fuel for purposes of Commission review and subsequent FAC proceedings" and (2) those credits and charges that "should be deferred for consideration and review as part of IPL, Vectren's, and NIPSCO's next basic rate proceedings." June 1st Order, pp. 37-39.

Q12. What Midwest ISO costs has NIPSCO deferred?

A12. The Midwest ISO costs deferred for review and recovery in this proceeding (the "Deferred Costs") are: (1) costs billed to NIPSCO by the Midwest ISO beginning August 1, 2006 under Schedules 10, 10 FERC, 16, 17, 24, and 26; (2) other non-FAC related charges assessed by the Midwest ISO as a result of NIPSCO taking transmission service and operating under the Midwest ISO TEMT; and (3) costs incurred by NIPSCO to construct and maintain the interface with the Midwest ISO and which have not been reimbursed by the Midwest ISO.

Q13. Were the Deferred Costs reasonable, necessary and incurred in conformance with the June 1st Order?

A13. Yes. These costs are assessed pursuant to the Midwest ISO's FERC-approved tariffs or otherwise required to be incurred in order for NIPSCO to participate in the Midwest ISO. All of the Deferred Costs are prudent costs incurred due to the Company's participation in the Midwest ISO and are necessary to ensure the provision of adequate and reliable service to NIPSCO's customers.

II. NIPSCO'S PROPOSED RA TRACKER

Q14. Please describe NIPSCO's proposed RA Tracker.

A14. The RA Tracker will provide a method for: (1) recovery and pass-through of certain RTO Costs and Revenues; (2) recovery of the purchased power costs; and (3) the allocation of net revenues from NIPSCO's off-system sales. Ms. Miller explains the mechanics of the RA Tracker. NIPSCO Witness Frank A. Shambo discusses the policy considerations supporting approval of the RA Tracker and the allocation of net revenues from NIPSCO's off-system sales.

Q15. Do you support the Commission's approval of NIPSCO's proposed RA Tracker?

A15. Yes. The RA Tracker will provide an ongoing method for recovery of: (1) the RTO Costs (in the Midwest ISO energy markets as well as the soon to be implemented Ancillary Services Market); (2) prudently-incurred purchased power costs; and (3) prudently-incurred capacity costs. The RA also implements NIPSCO's proposed off-system sales sharing mechanism and the pass-through of various RTO credits.

The current RTO Costs that would be included in the RA include: (1) Midwest ISO administrative costs billed under Schedule 10 (ISO Cost Recovery Adder), a successor provision (including Schedule 10-FERC), or any successor tariff of the Midwest ISO; (2) Midwest ISO administrative costs billed under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder), or any successor tariff of the Midwest ISO; (3) Midwest ISO costs associated with purchased power such as Non-Asset and certain Asset Energy Amounts; (4) Midwest ISO administrative costs billed under Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder), or any successor tariff of the Midwest ISO; (5) Midwest ISO costs and revenues that are "socialized," which are often referred to as "uplift costs," such as the Real-Time Revenue Neutrality Uplift Amount; (6) certain Midwest ISO transmission costs assigned to NIPSCO pursuant to the Midwest ISO's TEMT including, but not limited to, Schedule 24 and Schedule 26; (7) fuel-related Midwest ISO amounts related to Revenue Sufficiency including (i) Day-Ahead Revenue Sufficiency Guarantee Distribution Amount; (ii) Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount; and (iii) revenue sufficiency make whole payments; (8) transmission revenues from Midwest ISO Schedules 7 and 8 and the revenues from Midwest ISO Schedules 1 and 2 associated with Schedules 7 and 8; (9) costs and revenues from transmission adjustments captured in the Midwest ISO Schedule 11; and (10) any other amounts billed pursuant to the Midwest ISO's tariff that have been approved for filing at FERC and that are not included in NIPSCO's FAC proceedings.

Q16. Please explain why the Commission should approve NIPSCO's proposed RA Tracker.

A16. The RA Tracker should be approved for the following reasons. First and foremost, the Midwest ISO charges and credits to be recovered under the RA Tracker are assessed pursuant to the Midwest ISO's tariffs and are a necessary cost as NIPSCO continues to provide safe, adequate, and reliable service to its customers.

Second, the costs associated with purchased power are reasonable and necessary for the provision of safe, adequate, and reliable service to the Company's customers. The transactional purchased power costs will be subject to a benchmark that I will discuss later in my testimony. That benchmark will assist the Commission in determining that the purchased power costs are reasonable.

Third, the RA tracker properly recognizes that RTO Costs and purchased power costs are variable in amount from year to year and quarter to quarter. The level of these charges and credits varies with fluctuations in market demand, pricing, weather, and economic conditions. The timing of these charges and credits is also variable. Moreover, the RTO Costs may arise through refunds or additional charges ordered by FERC. The RTO Costs are also substantial in the aggregate and in individual amounts. FERC rulemakings, litigated proceedings, refunds, additional charges, actions of the Midwest ISO, new generation, loss of generation, variation in loads and customer levels within the Midwest ISO's footprint, and the normal vagaries of weather and economic and business cycles all serve to make these credits and charges outside NIPSCO's control and variable in nature. The ability to timely recover Midwest ISO charges on an ongoing basis is important to NIPSCO's financial well being and to the accuracy of price signals sent to the Company's customers. The Company's approach is consistent with prior Commission treatment of similar costs.

Specifically, in authorizing PSI Energy's ability to track RTO costs, the Commission recognized that the Midwest ISO costs and revenues are: "(1) the result of decisions by the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI." *PSI Energy, Inc.*, Cause No. 42359 (IURC 5/18/04), p. 120. The Commission also ruled similarly in *Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery Of Indiana, Inc.*, Cause No. 43111 (IURC 8/15/07), p. 31.

As a public policy matter, it is important that NIPSCO's participation in an RTO continues to be supported and that utilities are also encouraged to make capital investments to upgrade their transmission systems so that the benefits of participation in an RTO are fully realized. Section 1241 of the Energy Policy Act of 2005 ("EPAct 2005") directed FERC to adopt rules that would promote capital investments in transmission facilities. In response to that directive, on July 20, 2006 in Docket No. RM06-4-000, FERC approved in its Order No. 679, Promoting Transmission Investment through Pricing Reform. That Order provides a framework for encouraging utilities, which own the vast majority of transmission facilities, to make investments in transmission facilities. In the same Order, the Commission permits utilities to recover a return on such investment on a timely basis, as well as to earn an incentive rate of return on transmission investments (which would be higher than the standard Midwest ISO rate of return of 12.38% without the incentive).

Q17. Will the RA also provide a mechanism for the recovery of reliability upgrades to the transmission system?

A17. Yes. NIPSCO will be assessed charges for reliability upgrades to the transmission system in the Midwest ISO footprint pursuant to Attachment FF - Transmission Expansion Planning Protocol and Attachment GG - Network Upgrade Charge of the TEMT, which are recoverable through the FERC-approved Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan. Reliability upgrades include generator interconnection projects and transmission delivery service projects, identified in the MISO Transmission Expansion Plan ("MTEP"), required to maintain the reliability of the system. The cost of these upgrades will not be borne solely by the transmission owner constructing the upgrade, but will be shared among transmission owners according to a formula defined in the TEMT. Thus, NIPSCO and all Midwest ISO transmission owners will be allocated a portion of the cost of reliability upgrades that are constructed by any Midwest ISO transmission owners.

The cost of the transmission upgrades that the Midwest ISO approves through its MTEP are assessed to Transmission Owners, such as NIPSCO, pursuant to the methodology set forth in Attachment O of the Midwest ISO's tariff, which are assessed through Attachment FF. Thus, NIPSCO developed its proposed RA Tracker to recover these increased costs flowing through Attachment FF.

Q18. Please further address the costs and charges identified above.

A18. Attachment FF and Attachment GG of the TEMT and Schedule 26 were accepted for filing by FERC on February 3, 2006 in its Order in Docket No. ER06-18-000. Attachment FF is the core cost allocation policy document which details the process to be used by the Midwest ISO to evaluate and develop expansion projects for the MTEP, in addition to the allocation and recovery of costs of transmission expansion projects.

Attachment GG sets forth the methodology for calculating charges associated with the network upgrades developed pursuant to Attachment FF. The charges calculated under Attachment GG will be collected under Schedule 26. Attachment FF allocates costs of transmission projects in other areas to NIPSCO for projects that are included in MTEPs subsequent to MTEP 2005.

Q19. Will the Midwest ISO assess NIPSCO charges associated with economic upgrades?

A19. Yes. NIPSCO will be assessed charges for economic upgrades to the Midwest ISO transmission system that are built by other transmission owning members of the Midwest ISO. Economic upgrades are those network upgrades that are beneficial to one or more market participants, but are not necessary to meet NERC reliability criteria during the planning horizon that is used in the MTEP.

On November 1, 2006, the Midwest ISO made a filing with FERC, in Docket No. ER06-18-004, detailing the methodology to be used for identifying qualifying economic upgrades and the methodology to be used for recovering those costs. The Midwest ISO's methodology for recovering transmission upgrade costs results in regional cost sharing for these projects which means that a portion of these costs will be allocated and charged to NIPSCO.

Q20. Will the Company be assessed costs associated with reactive power?

A20. In the future, NIPSCO may be assessed charges for reactive power service provided by generators in NIPSCO's control area. Under current FERC policy, independent generators may file a rate schedule with FERC for recovery of reactive power service costs incurred by the generator. Such charges would be recovered through the Midwest ISO's Schedule 2 - Reactive Power Service.

Q21. Does NIPSCO scrutinize charges it receives for RTO costs?

A21. Yes. NIPSCO closely scrutinizes its Midwest ISO invoices to be certain that NIPSCO, and in turn the Company's retail customers, are not overcharged by the Midwest ISO through errors or unreasonable operations. NIPSCO shadows the multiple Settlement and Resettlement Statements received from the Midwest ISO for every operating day. As part of this process, the Company recalculates many of the hourly charges and files formal disputes when the charges are not supported by published rules for the market or correct operating data. Similarly, representatives of NIPSCO, since the beginning of Midwest ISO and continuing today, actively participate in the Midwest ISO Stakeholder process.

Q22. Please explain NIPSCO's proposed recovery of purchased power costs.

A22. In the past, purchased power costs have been recoverable in the FAC, subject to a "benchmark," which was utilized as a surrogate for the fuel component of the costs. In this proceeding NIPSCO proposes to include its purchased power costs in its RA Tracker, subject to a benchmark. NIPSCO also proposes to recover prudently-incurred capacity costs, as described in more detail by NIPSCO Witness Bradley K. Sweet.

Q23. Why is NIPSCO proposing to exclude purchased power costs from the FAC and instead include them in the RA Tracker?

A23. As explained in more detail by Mr. Shambo, NIPSCO believes that excluding purchased power costs from the FAC is consistent with the logic of the Revised Purchased Power Benchmark approved in NIPSCO's FAC71 sub-docket, which allows for recovery of certain purchased power costs via a tracker mechanism approved pursuant to Ind. Code § 8-1-2-42(a).

Q24. Why is NIPSCO proposing to utilize the benchmark you previously identified in its RA Tracker?

A24. First, I would note that the Midwest ISO determines which Day-Ahead Resource offers are necessary to meet the Day-Ahead Demand bids including virtual offers and bids and then commits additional generation in the Reliability Assessment Commitment ("RAC") process to meet the Midwest ISO-wide forecasted load and reserve requirements. If additional resources are required, the Midwest ISO initiates start signals to the most cost efficient generation resources available while still maintaining transmission reliability. When NIPSCO buys power as part of the Midwest ISO's economic dispatch regime, those purchases represent the least cost resources available to NIPSCO and, therefore, those costs should be recoverable. The benchmark simply provides a check for reasonableness for the Company and Commission.

Q25. Please describe the proposed benchmark.

A25. Each day a "Benchmark" will be established based upon a generic Gas Turbine ("GT"), using an effective GT heat rate of 12,500 btu/kwh and a fuel cost based on the day ahead natural gas prices for the New York Mercantile Exchange Chicago City Gate, plus a $.17/ mmbtu gas transport charge. NIPSCO seeks to recover from its retail customers the cost of purchased power in the following circumstances:

(a) Purchases made in the course of the Midwest ISO's economic dispatch regime to meet jurisdictional retail load are a reasonable expense and are fully recoverable up to their actual cost or the Benchmark, whichever is lower.

(b) In each individual hour that purchased power costs exceed the Benchmark, purchases made under the following conditions would be recoverable as follows:

- If NIPSCO has generating units available to the Midwest ISO that were offered into the Midwest ISO market at expected cost and which were not selected by the Midwest ISO and the utility purchased power over the benchmark, 100% of the purchase power costs up to the amount of such available capacity are recoverable as Midwest ISO economic dispatch.
- If, after considering the above parameter, the sum of unplanned full forced outages, qualifying environmental derates, partial outages, and qualifying scheduled maintenance outages total 11% or more of NIPSCO's seasonal generating fleet capacity, 100% of purchase costs over the Benchmark for purchases made to account for such outage level are recoverable up to the amount of the outage capacity.
- If purchases were made to account for qualifying environmental derates, 100% of the purchase costs over the Benchmark for such purchases are recoverable up to the amount of the derated capacity.
- For purchases not subject to 100% recovery as described in the above parameters, 85% of the purchase costs over the Benchmark for such purchases are recoverable up to the FERC approved Midwest ISO definition of scarcity pricing.

Q26. Please explain how participation in the Midwest ISO energy markets has impacted NIPSCO's economic dispatch decision-making and the resulting impact on power purchases.

A26. Prior to the Midwest ISO market, NIPSCO personnel made the decision whether to dispatch NIPSCO units or to purchase power economically in the wholesale market. Today, the Midwest ISO performs a security-constrained unit commitment and security-constrained economic dispatch using day-ahead offers and bids. In addition, the Midwest ISO's RAC process determines the most efficient additional resources to be committed, taking into consideration transmission reliability, unit start-up, no load and energy costs and other unit operating constraints to meet the forecasted load and reserve requirements. In real-time, NIPSCO receives five-minute dispatch instructions from the Midwest ISO to dispatch the most economic on-line resources available in the Midwest ISO footprint. With the advent of the Ancillary Services Market ("ASM"), dispatch instructions will be sent every few seconds. Those directions take into consideration the effects of transmission congestion and losses.

The Midwest ISO makes the decision which NIPSCO generating resources are to be dispatched and at what level. The Midwest ISO bases its decision on its security-constrained economic dispatch model, thereby utilizing the most efficient locational-specific resources available in the Midwest ISO footprint. Depending on the specific conditions and inputs which can only be evaluated by the Midwest ISO on a regional basis, the Midwest ISO's directive may be for NIPSCO to purchase power from the market rather than the Midwest ISO calling for NIPSCO's internal generation. As a result, NIPSCO may, on occasion, be directed by the Midwest ISO to make economy purchases at what may appear to be a higher cost than NIPSCO's own resources. Those Midwest ISO directed purchases can even be at levels above the Benchmark.

Q27. Is the Benchmark mechanism in the public interest?

A27. Yes. Use of a daily Benchmark captures the variability of fuel prices over time. In addition, the Benchmark addresses the recoverability of costs incurred when the Midwest ISO elects to utilize other more cost efficient generation in the footprint in lieu of starting higher cost NIPSCO generation, benefiting NIPSCO's jurisdictional retail customers. Finally, NIPSCO's proposal provides a detailed step-by-step process to identify, review and address the appropriateness and recovery of purchased power costs in excess of the Benchmark.

III. <u>TARIFF REVISIONS</u>

Q28. Are you familiar with the terms "Curtailment" and "Interruption" as used in NIPSCO's Proposed Tariffs?

A28. Yes. The reduction of a Customer's load at the request of NIPSCO pursuant to NIPSCO's tariffs for economic purposes would be an Interruption of load. A Curtailment of load would be the reduction of a Customer's load at the request of NIPSCO pursuant to NIPSCO's tariffs for reliability. Curtailment load must qualify as a Load Modifying Resource ("LMR") pursuant to the Midwest ISO's tariffs or its successor.

Q29. Please define the term "Load Modifying Resource".

A29. An LMR is also defined as a demand resource or behind the meter generation resource.

Q30. What are the requirements of an LMR?

A30. Under the current Midwest ISO tariff, as filed with FERC, an LMR must be: (i) equal to or greater than 100 kW (a grouping of smaller resources may qualify in meeting this standard); (ii) available to be scheduled for a Load reduction at the targeted Load reduction level or by moving to the firm service level with no more than 12 hours Start Time; (iii) Once Scheduling Instructions are given by the Midwest ISO that require a Load reduction, the Customer must be capable of ramping down its load to meet the targeted Load reduction level or achieve the firm service level by the Hour designated by the Midwest ISO's Scheduling Instructions; (iv) Once the targeted level of Load reduction or firm service level is achieved, the Customer must be able to maintain the target level of Load reduction or firm service level for at least four continuous hours; (v) The Customer must be capable of being interrupted at least five (5) times during the Summer Season (when called upon by the Midwest ISO) during any Planning Year for which NIPSCO receives credit as a Planning Resource. The Midwest ISO has the right to file for changes in these requirements with FERC.

IV. <u>SUMMARY</u>

Q31. Please summarize your testimony.

A31. The Commission has approved NIPSCO's participation in the Midwest ISO and it is appropriate that the Commission should approve the recovery of the reasonable charges and credits NIPSCO incurs as a result of that participation. The RA described herein will allow NIPSCO to timely recover these reasonable charges and credits incurred in the provision of reliable and economic service to its retail customers. NIPSCO, has been, and will continue to be, committed to the stakeholder process as a member of the Midwest ISO, thereby providing input into the design and reasonableness of the Midwest ISO charges and credits. The Commission has found in other cases that these charges and credits are variable and not readily predictable and that as such a periodic recovery process is necessary. The Commission should also recognize that by providing a recovery mechanism as proposed herein, customers will receive appropriative price signals. At the same time, NIPSCO would receive sufficient and timely cost recovery, thereby protecting NIPSCO's continued ability to reliably serve its customers. The Commission should approve the Benchmark proposed herein as a fair and reasonable yardstick for measuring the economical operation of NIPSCO's delivery of energy to our retail customers. Finally, the Commission should accept NIPSCO's distinction between "Curtailment" and "Interruptible."

Q32. Does this conclude your prepared direct testimony?

A32. Yes, it does.

VERIFICATION

I, Curtis L. Crum, Director, Generation Dispatch and Energy Management for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Curtis L. Crum

Curtis L. Crum

Date: August 29, 2008

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Petitioner's Exhibit KRC-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

KELLY R. CARMICHAEL

DIRECTOR OF ENVIRONMENTAL PERMITTING AND REGULATORY SERVICES

VERIFIED DIRECT TESTIMONY OF KELLY R. CARMICHAEL

Q1. Please state your name, job title, employer and business address.

A1. My name is Kelly R. Carmichael. My title is Director of Environmental Permitting and Regulatory Services for NiSource Corporate Services Company ("NCS"). My business address is 801 East 86th Avenue, Merrillville, Indiana 46410. I am testifying on behalf of Northern Indiana Public Service Company ("NIPSCO" or "Company").

Q2. Please summarize your educational background.

A2. I received a Bachelor of Science in Physics from Illinois State University in 1994, a Bachelor of Science in General Engineering from the University of Illinois at Urbana-Champaign in 1995 and a Master of Science in Environmental Engineering from the University of Illinois at Urbana-Champaign in 1996.

Q3. What are your current responsibilities as Director of Environmental Permitting and Regulatory Services?

A3. In this position I have direct responsibility for tracking and analyzing the development of environmental regulations affecting the operating companies within the NiSource corporate organization ("NiSource affiliates" or "affiliates"), including NIPSCO. Another primary responsibility is to provide environmental permit services for air, water and solid waste needs for NiSource affiliates, including NIPSCO.

Q4. Please describe your professional experience.

A4. My professional experience includes various technical and management positions in the environmental field primarily for the steel and utility industries. In 2001, I joined NCS and have held several positions with increasing levels of responsibility, focusing primarily on environmental permitting, regulatory analysis and compliance plan development.

Q5. Have you previously testified before this or any other regulatory commission?

A5. No.

Q6. What is the purpose of your testimony in this Cause?

A6. The purpose of my testimony is to discuss current and emerging environmental regulations that are expected to drive future compliance activities for NIPSCO. I will also summarize the NIPSCO generation fleet environmental compliance program. NIPSCO Witness Phil Pack discusses NIPSCO's recovery of its environmental compliance costs.

Q7. What environmental statutes and regulations affect NIPSCO?

A7. The operations of NiSource affiliates, including NIPSCO, are subject to extensive and evolving federal, state and local environmental laws and regulations intended to protect the public health and the environment. Such environmental laws and regulations affect operations that have impact on air, water and/or land.

The main federal statutes with which NIPSCO must comply are the Clean Air Act ("CAA") and its amendments, the Clean Water Act ("CWA"), the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and the Resource Conservation and Recovery Act ("RCRA").

Q8. Please describe the Clean Air Act.

A8. The CAA is divided into several sections, or titles, which address airborne emissions with the ultimate goal of reducing impacts on public health and the environment from man-made pollutants.

The CAA amendments of 1990 introduced a new nationwide approach to reduce the emission of acidic air pollutants. The Acid Rain program was designed to reduce electric utility emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") primarily through a market based cap and trade approach. While the SO_2 reductions were achieved in two phases via the establishment of lowered overall emissions caps, NOx emission controls were required using a two-phased control technology based emission reduction program.

Also pursuant to the CAA, the U.S. Environmental Protection Agency ("EPA") is required to establish National Ambient Air Quality Standards ("NAAQS") to protect human health and the environment. NAAQS have been established and continue to be evaluated and lowered most recently for ozone and particulate matter. Electric utilities have been identified as contributing sources to both ozone and particulate matter nonattainment areas primarily due to emissions of SO_2, NOx and particulate matter. SO_2

and NOx are both considered precursors to the formation of particulate matter and NOx is considered a precursor to the formation of ozone. Once NAAQS are set or lowered, the EPA and states go through a process to designate areas either as attainment or nonattainment.

To achieve compliance with the NAAQS, states must evaluate and implement reduction measures through the development of state implementation plans ("SIPs") for emissions, including SO_2, NOx and particulate matter, that impact nonattainment areas. In cases of regional transport issues where upwind sources may impact downwind nonattainment areas, the EPA has developed regional control programs, and states have utilized provisions in the CAA to force revisions to SIPs in upwind states.

For NIPSCO, the Bailly Generating Station is located in the Porter County ozone nonattainment area. The Indiana Department of Environmental Management ("IDEM") submitted a petition to the EPA seeking redesignation of Porter County to attainment status for the ozone NAAQS. The EPA approval for the Porter County ozone redesignation is undergoing evaluation and may be delayed until after the 2008 ozone season due to ozone monitoring data values in excess of the NAAQS in 2007. In addition, on March 12, 2008 the EPA further lowered the ozone NAAQS which may preclude the approval of the ozone redesignation request and may result in Porter County remaining classified as nonattainment for the ozone NAAQS. The Michigan City Generating Station is located in LaPorte County. LaPorte County, which was previously designated as nonattainment for ozone, was redesignated to attainment in 2007.

However, LaPorte County may further be redesignated back to nonattainment due to the March 12, 2008 the EPA lowering of the ozone NAAQS.

The EPA has also determined that, for purposes of achieving ozone and particulate attainment, emissions from certain upwind states, including Indiana, 'contribute significantly' to downwind state nonattainment areas. As a result, the NOx SIP Call ("Call" being the EPA requirement, or call, for individual states to develop SIPs to reduce NOx emissions) and Clean Air Interstate Rule ("CAIR") regional emission control programs were developed to address regional pollutant transport issues and are more fully described below. Emission reductions from NIPSCO generating stations have been identified to address both local nonattainment as well as regional pollutant transport issues.

In December 2001, the EPA approved regulations developed by the State of Indiana to comply with the EPA's NOx SIP Call. The NOx SIP Call requires certain states, including Indiana, to reduce NOx emissions during the ozone season (May 1 through September 30) from source categories including industrial and utility boilers. Compliance with the NOx limits contained in these rules was required by May 31, 2004.

On March 10, 2005, the EPA finalized CAIR regulations to address the regional transport of air pollutants and assist states in achieving attainment of the NAAQS in the eastern United States. The CAIR regulations built upon existing CAA programs to further reduce emissions of NOx and SO_2. The CAIR established phased reductions of NOx and SO_2 from sources, including electric utilities in Indiana, by establishing an annual emissions cap for NOx and SO_2 and an additional cap on NOx emissions during the ozone control season. This was accomplished by increasing the stringency of the EPA NOx SIP Call emissions trading program, establishing a new annual emissions reduction requirement for NOx and increasing the stringency of the SO_2 CAA Acid Rain emissions trading program. As an affected state, Indiana adopted final rules on November 1, 2006 to implement CAIR which became effective on February 25, 2007.

On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the federal CAIR in its entirety ("the decision"). Any petition for rehearing must be filed within 45 days of the decision. At this time, the CAIR regulations in Indiana remain in effect. However, the State of Indiana will likely need to modify or repeal and replace the state CAIR regulations in response to the decision and final resolution. At the time of this testimony there was some indication that an interim CAIR approach would be sought until the issues identified by court could formally be resolved. In any case, the underlying requirements for states to achieve compliance with the NAAQS remain in effect, and as such, states are required to develop SIPs to achieve attainment with the NAAQS. In addition, it is likely that the EPA and/or congressional action will be needed to address the regional transport issue.

In order to meet the CAA requirements for hazardous air pollutants ("HAPs") reductions, including mercury, the EPA implemented the Clean Air Mercury Rule ("CAMR") to reduce and cap mercury emissions from coal-fired power plants. The CAMR established "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and created a market-based cap and trade program that was designed to reduce nationwide utility emissions of mercury in two phases. The first phase was scheduled to begin January 1, 2010. The second phase was scheduled to begin in 2018 when coal-fired electric generating stations would have been subject to a more stringent mercury emissions cap. On October 3, 2007, the State of Indiana adopted a rule which became effective on February 3, 2008 to implement the EPA's CAMR. On February 8, 2008, the U.S. Court of Appeals for the D. C. Circuit vacated the CAMR. If any party wants to appeal the decision, a petition for certiorari would need to be filed with the Supreme Court by August 16, 2008. If the decision to vacate CAMR stands, the EPA would likely return to the development of a Maximum Achievable Control Technology ("MACT") standard under the existing CAA requirements. Under a MACT standard the EPA is required to develop control technology requirements for HAPs, including mercury. The resolution of this legal action and the EPA's response will affect the implementation and timing of the installation of controls to address HAP reduction obligations.

The EPA is also required under the CAA to address regional haze issues. On October 3, 2007, the State of Indiana adopted a rule to implement the EPA Best Available Retrofit Technology ("BART") requirements for reduction of regional haze. The rule became effective February 22, 2008 requiring BART controls within five years (2013). The language of the final rule relied upon the provisions of the Indiana CAIR to meet requirements for NOx and SO_2 BART controls and would not have imposed any additional control requirements on coal-fired electric generation station emissions of these pollutants. As part of the BART analysis process, IDEM continues to evaluate the potential impact of particulate matter from electric generating units to determine if there are impacts on Class I areas. If a BART exemption is not available, for example as a result of the CAIR rule being vacated, then further NOx and SO_2 reductions may be required from NIPSCO generating stations. The requirement for additional control would be contingent upon further regional haze impact analyses identifying contributing sources.

Q9. What actions has NIPSCO taken to achieve compliance with the Acid Rain provisions of the CAA?

A9. NIPSCO has, over time, significantly reduced NOx and SO_2 emissions resulting from operations in order to meet the requirements of the CAA Acid Rain program. NIPSCO has implemented NOx control measures including installation of separated overfire air on Units 7 and 8 at Bailly Generating Station, Unit 12 at Michigan City Generating Station and Unit 14 at Schahfer Generating Station. In addition, Units 7 and 8 at Bailly Generating Station and Units 17 and 18 at Schahfer Generating Station are controlled using wet flue gas desulfurization ("FGD") systems. The remaining high sulfur coal-fired unit (Unit 12 at Schahfer Generating Station) was converted to include a blend of low sulfur Powder River Basin coal prior to the commencement of the first phase of the Acid Rain program reductions.

Q10. What actions has NIPSCO taken to achieve compliance with the EPA NOx SIP Call and CAIR programs?

A10. As described above, the CAIR regulations have been vacated and are pending review, potential appeal and further action at the state, the EPA and potentially congressional levels. However, underlying CAA requirements, including requirements for states to develop SIPs to comply with NAAQS, remain in effect. It is expected that control requirements similar to or more stringent than CAIR will eventually be required. In the interim, the court determined that the NOx SIP Call would continue in the absence of CAIR. NIPSCO's efforts to date to achieve compliance with the EPA NOx SIP Call and CAIR regulations can be summarized as follows:

- In order to address the requirements for NOx reduction obligations, NIPSCO developed a NOx compliance plan. The plan included the installation of Selective Catalytic Reduction ("SCR") equipment. In implementing its NOx compliance plan, NIPSCO has expended approximately $290 million as of December 31, 2007.
- In a petition initially filed with the IURC in December 2006 and subsequently updated, NIPSCO provided plans for the first phase of the emission control construction required to address the first phase of the CAIR requirements and the Commission approved the timely recovery of certain costs.

Q11. Are additional pollution control technology installations expected in the future?

A11. Yes. Although both CAIR and CAMR are currently vacated, further emission reductions will be required to meet CAA requirements including more stringent NAAQS, MACT and potentially BART as described above.

Q12. Are there other future environmental regulations expected to affect NIPSCO?

A12. Proposals for voluntary initiatives and mandatory controls are being discussed both in the United States and worldwide to reduce greenhouse gas ("GHG") emissions such as carbon dioxide ("CO_2"), a by-product of burning fossil fuels. Certain NiSource affiliates, including NIPSCO, engage in efforts to voluntarily report and reduce their GHG emissions. NiSource is currently a participant in the Department of Energy's 1605(b) and the EPA's Climate Leaders and Natural Gas Star programs. These programs promote voluntary reporting and reduction activities.

It is expected that legislation and/or regulations governing GHG emissions, including CO_2, will be established at some point in the future. Currently, there are no federal regulations that specifically regulate emissions of CO_2 into the air. However, recent developments in the U.S. Congress, various state legislatures, and federal court decisions regarding GHG emissions indicate ongoing interest in regulating emissions of CO_2.

At the federal level, Congress has been holding a succession of committee hearings in both the House of Representatives and the Senate to gather information on climate change and possible approaches to limiting or controlling GHG emissions. A number of proposals have been introduced that would result in regulation of emissions for the electric generating sector alone or for the entire economy. In June 2008, the Senate debated, but did not vote on, the Lieberman-Warner Climate Security Act of 2008 which included a cap and trade program to limit GHG emissions from a multitude of sources including coal-fired utilities. It is expected that climate bills will be introduced in 2009 for further debate in both the House of Representatives and the Senate.

A number of states have moved forward with GHG emission requirements in the absence of federal legislation or regulation. For example, in the Midwest, six U.S. Governors and one Canadian Premier signed the Midwestern Greenhouse Gas Accord on November 17, 2007 with the intent to:

- establish GHG reduction targets and time frames consistent with signing states' targets;
- develop a market-based and multi-sector cap-and-trade mechanism to help achieve those reduction targets;
- establish a system to enable tracking, management, and crediting for entities that reduce GHG emissions; and
- develop and implement additional steps as needed to achieve the reduction targets, such as a low-carbon fuel standards and regional incentives and funding mechanisms.

The State of Indiana has signed on as an observer at this time but is not directly participating. In addition to state legislative activity, a decision of the U.S. Supreme Court in *Massachusetts v. Environmental Protection Agency*, 127 S.Ct. 1438 (2007), requires the EPA to make certain determinations regarding regulation of GHG emissions from motor vehicles. On April 2, 2007, in a 5-4 decision, the Supreme Court held that GHG emissions, including CO_2, fit within the CAA definition of an "air pollutant" and that the EPA has the statutory authority to regulate the emission of GHG from new motor vehicles. Although this case was limited to new motor vehicles, the Court's holding could have far reaching implications to the entire regulated community, including the fossil-fuel fired electric generation sector. The Court did not order the EPA to regulate GHG emission but the decision clearly states that the EPA has the authority to do so. On

July 11, 2008, the EPA released an Advanced Notice of Proposed Rulemaking ("ANPR") seeking comment on the regulation of GHG emissions, including those from the fossil-fuel fired electric generation sector.

Q13. Has NIPSCO taken any steps to prepare for any programs that control or limit the emission of CO_2?

A13. Yes. For example, NIPSCO considers heat rate improvement projects in its capital budget to increase the efficiency of its electric generation and therefore, reduce the rate of CO_2 emissions. NIPSCO recently replaced the Unit 12 steam turbine at the Michigan City Generating Station utilizing a dense pack configuration which improves the efficiency of the electric generation process. Additional potential steam turbine replacements will also consider this configuration, which would improve the efficiency of the steam cycle of those units.

NIPSCO is also looking at generation options that will help prepare for future limits on CO_2 emissions. NIPSCO has purchased the Sugar Creek natural gas fired combined cycle gas turbine ("CCGT"). This facility produces electricity at approximately half the CO_2 rate as that of a traditional coal-fired boiler. NIPSCO's acquisition of wind power, as a renewable option, was approved by the Indiana Utility Regulatory Commission on July 24, 2008, in Cause No. 43393.

NIPSCO will be required to significantly further reduce as well as potentially utilize market trading mechanisms should GHG reduction requirements become effective similar to reductions currently being discussed and debated in Congress.

Q14. Has NIPSCO been impacted by the EPA enforcement initiative on New Source Review?

A14. Yes. In late 1999, the EPA initiated New Source Review ("NSR") enforcement actions against several industries, including the electric utility industry, concerning rule interpretations that have been the subject of recent (prospective) reform regulations. NIPSCO received and responded to the EPA information requests on this subject, most recently in June 2002. The EPA issued a Notice of Violation ("NOV") to NIPSCO on September 29, 2004, for alleged violations of the CAA and the SIP. Specifically, the NOV alleges that modifications were made to certain boiler units at the Michigan City, Schahfer and Bailly Generating Stations between the years 1985 and 1995 without obtaining appropriate air permits for the modifications. In related settlement agreements for other utilities, the installation of additional air pollution controls, payment of penalties and supplemental environmental projects have been required.

Q15. Has the NOV been resolved?

A15. No. NIPSCO continues to have ongoing dialogue with the EPA, U.S. Department of Justice and the IDEM on the matter.

Q16. Please describe the Clean Water Act.

A16. The CWA establishes water quality standards for surface waters as well as the basic structure for regulating discharges of pollutants into the waters of the United States. Under the CWA, the EPA implemented pollution control programs such as setting wastewater standards for industry including for electric utilities. In addition, the CWA made it unlawful to discharge any pollutant from a point source into navigable waters unless a permit was obtained. The National Pollutant Discharge Elimination System ("NPDES") permit program implements the CWA's provisions and prohibits unauthorized discharges by requiring a permit for point sources impacting waters of the United States.

The Great Lakes Water Quality Initiative ("GLI") program adds new, more stringent, water quality standards for facilities that discharge into the Great Lakes watershed, including NIPSCO's Bailly and Michigan City Generating Stations located on Lake Michigan. The State of Indiana has promulgated its regulations for this water discharge permit program and has received final approval of the EPA. Two main issues remain to fully comply with the GLI requirements in current NIPSCO NPDES permits.

First, the NPDES water discharge permit for NIPSCO's Michigan City Generating Station became effective on April 1, 2006 and requires that the facility meet the GLI discharge limits for copper by April 1, 2010. Recent sample results indicate that under the current configuration the limit cannot be met. NIPSCO is presently evaluating alternatives for meeting the discharge limits included in the NPDES permit.

Second, GLI based discharge limits for mercury have been established for both the Bailly and the Michigan City Generating Stations. One option to comply with these limits is to obtain a streamlined mercury variance ("SMV") from the IDEM. NIPSCO is in the process of collecting data to develop and implement pollution reduction program plans in order to demonstrate progress in reducing mercury discharge. NIPSCO will need to request and obtain a variance from the mercury limits or install waste water treatment technology to meet the stringent mercury discharge limits.

In addition to GLI requirements, Section 316(b) of the CWA requires that all large existing steam electric generating stations with cooling water intake structures deploy the best technology available to minimize adverse environmental impacts to fish and shellfish. The EPA's rule implementing Section 316(b) became effective on September 7, 2004. Litigation ensued, and on January 25, 2007, the Second Circuit Court remanded to the EPA for reconsideration the options in the regulation that provided for flexibility in meeting the requirements of the rule. Shortly thereafter, the EPA suspended the 316(b) Phase II Rule which governs cooling water withdrawals. The EPA then instructed state and regional regulators that permits implementing Section 316(b) could be issued using best professional judgment to determine the best technology available for reducing adverse environmental impact. Various parties submitted petitions for a *writ of certiorari* to the U.S. Supreme Court in early November 2007 seeking to reverse the Second Circuit Court's decision. On April 14, 2008, the U.S. Supreme Court granted the petitions limiting the review to one question. The Court will consider whether 316(b) authorizes the EPA to compare costs with benefits in determining the "best technology available for minimizing adverse environmental impact" at cooling water intake structures.

The EPA is expected to update the 316(b) Phase II Rule in the future to define the federal requirements of Section 316(b) for electric generating facilities. Under this rule, stations will either have to demonstrate that the performance of their existing fish protection systems meet the new standards or develop new systems, such as a closed-cycle cooling tower.

The NPDES permit for the Bailly Generating Station became effective on August 1, 2006 and was further modified and issued effective February 18, 2008 primarily to address the Section 316(b) rule status due to the previously described remand. Bailly Generating Station's cooling water intake structure will be required to meet the 316(b) requirements. Depending on the Supreme Court decision and agency action this could include the possibility of installation of cooling towers or the requirement to otherwise modify the intake structure.

The Spill Prevention Control and Countermeasure ("SPCC") regulations require reduction or elimination of the potential to contaminate surface water or soil with oil or other petroleum-based products. The regulations establish procedures, methods, equipment and other requirements for the prevention of the discharge of oil into navigable waters of the United States or adjoining shorelines. NIPSCO has prepared plans to address SPCC requirements. These plans address tanks, drums and equipment (such as transformers) that contain oil.

Q17. Please describe CERCLA and RCRA.

A17. CERCLA was promulgated in 1980 by the EPA to investigate and remediate closed, abandoned or uncontrolled waste management sites. Under CERCLA, the EPA prioritized historic waste management facilities across the United States. Based on its ranking system and other criteria, the EPA places sites on the National Priorities List. CERCLA requires parties that generated, transported or disposed of wastes at the facilities to pay for their investigation and cleanup. These parties are known as Potentially Responsible Parties ("PRPs").

RCRA establishes cradle to grave requirements for the generation, treatment, disposal or management of hazardous waste. It became effective in 1976 and underwent significant amendment in 1986. Part of the amendments in 1986, commonly called "Corrective Action," required facilities that obtained permits to treat, store or dispose of hazardous waste to investigate and remediate "Solid Waste Management Units." This authority extends to historic releases of contaminants and requires mitigation of their effects on human health and the environment. The cost of such remedial action can range from hundreds of thousands to several million dollars at each facility, depending on the nature and scope of historic waste management.

Q18. What actions has NIPSCO taken to achieve compliance with CERCLA and RCRA regulations ?

A18. NIPSCO is a PRP under CERCLA and similar state laws at two waste disposal sites. At both of these sites, NIPSCO shares in the cost of cleanup with other PRPs. At one site, the Remedial Investigation and Feasibility Study was submitted to the EPA in 2007. The EPA issued a proposed plan to remediate the site which is currently undergoing public comment. At the second site, a state-permitted landfill where NIPSCO contracted for fly ash disposal, NIPSCO agreed to conduct a Remedial Investigation and Feasibility Study.

Future corrective actions may be required in order to have these sites be deemed closed by the EPA.

On March 31, 2005, the EPA and NIPSCO entered into an Administrative Order on Consent under the authority of Section 3008(h) of RCRA for the Bailly Generating Station. The RCRA Corrective Action Administrative Order requires NIPSCO to identify the nature and extent of releases of hazardous waste and hazardous constituents from the facility. NIPSCO must also remediate any release of hazardous constituents that present an unacceptable risk to human health or the environment. Investigation activities are complete and NIPSCO is awaiting the EPA comments on proposed remedial actions. Costs are anticipated to be several million dollars. The Schahfer and Michigan City Generating Stations will be subject to Corrective Action under RCRA. Costs are anticipated to be several million dollars at each location. The timing of the work is dependant upon the EPA, but is anticipated to commence sometime during the next several years.

On September 13, 2006, IDEM advised NIPSCO that further investigation of historic releases from two previously removed underground storage tanks at the Schahfer Generating Station would need to be investigated. NIPSCO completed an investigation of potentially impacted soils and groundwater in 2007 and submitted results to the IDEM Leaking Underground Storage Tank section. As of the end of June 2008, IDEM has not responded.

On April 9, 2008, NIPSCO submitted written notification to the IDEM Leaking Underground Storage Tank section regarding the discovery of a leaking used oil underground storage tank at the Schahfer Generating Station. The tank and associated piping were removed from service, emptied of product and cleaned, and an Initial Site Characterization Study was begun. Further investigation and remedial action are pending Agency response.

It is also anticipated that NIPSCO will be designated a PRP by the EPA at other historic waste disposal sites under CERCLA. NIPSCO provides information to the EPA when requested regarding historic waste management activities. In all cases, there are other PRPs and costs are typically shared based on volume of waste disposed or other criteria. Costs can range from several thousand dollars to several million dollars depending upon the number of PRPs and their ability to pay for cleanup costs.

Q19. What future RCRA environmental regulations are expected to affect NIPSCO?

A19. In the 2000 Bevill Determination,[1] the EPA determined that regulation of coal ash as hazardous waste under RCRA subtitle C is not warranted. The EPA did, however, express the opinion that these materials, when deposited in landfills, surface impoundments or used as minefill, should be regulated as RCRA subtitle D wastes. While the EPA has not yet determined whether the management of coal ash should be federally regulated or governed by state oversight, it is widely expected that some form of regulation resembling RCRA subtitle D standards will be imposed in the near future.

[1] In May 2000 EPA determined that fossil fuel combustion wastes "do not warrant regulation under Subtitle C of RCRA." 65 Fed. Reg. 32214 (May 22, 2000).

Q20. How is NIPSCO planning to meet these future RCRA regulations?

A20. To a large extent, NIPSCO's current coal ash management practices already meet the proposed standards. The permitted disposal facility at the Schahfer Generating Station has a composite liner and utilizes a leachate collection system. The facility has a network of twenty-eight groundwater monitoring wells which are sampled twice per year. It is anticipated that groundwater monitoring systems will be required at the Bailly and Michigan City Generating Stations.

NIPSCO also utilizes dry fly ash handling systems for virtually all of its fly ash with one minor exception, that being a small fraction of the fly ash from the Michigan City Generating Station, which is sluiced to a holding pond and periodically removed for disposal at the Schahfer disposal facility.

Q21. What is the projected timeline and projected cost of meeting these future RCRA regulations?

A21. Potential future costs will largely depend on the outcome of the investigations of the historic sites and the EPA or IDEM cleanup levels. Until the details of these investigations are known, potential costs to comply can not be estimated. Based on the EPA's past actions at the Bailly Generating Station, the costs could be significant.

Q22. In general terms, how does NIPSCO analyze the impact of new regulations?

A22. In order to provide up to date regulatory and strategic analyses, NIPSCO utilizes internal strategic planning groups, outside consultants and maintains an active role in utility industry technical and regulatory committees.

Internally, NIPSCO reviews compliance plans on a periodic basis. The periodic reviews are performed with the assistance of outside engineering and consulting firms. Engineering studies are conducted to verify or modify the compliance plan options that incorporate the latest information, costs and effectiveness of available control technologies and systems. These studies include research on the technical feasibility and capabilities of pollution controls, as well as, identify feasible compliance strategy options for each requirement scenario. The studies are intended to optimize compliance plans by weighing, among other factors, technology application risk, effectiveness, costs, impacts to operations and schedule.

Q23. NIPSCO Witness Victor Ranalletta addresses the results of studies that were performed by Burns & McDonnell Engineering Co., Inc. ("BMcD") estimating the cost of demolishing certain NIPSCO electric generating stations and remediating the sites. Have you reviewed the environmental remediation assumptions used by BMcD in the demolition cost studies?

A23. Yes.

Q24. In your opinion are the environmental remediation assumptions used by BMcD reasonable?

A24. Yes.

Q25. Please summarize your testimony.

A25. NIPSCO must comply with a multitude of existing environmental regulations, including the CAA, and its amendments, the CWA, CERCLA and the RCRA. In addition to existing regulations, it is expected that legislation or regulations governing further environmental controls will be enacted in the near future. NIPSCO continues to carefully manage its environmental control programs and evaluate potential future requirements on an ongoing basis.

Q26. Does this conclude your prepared direct testimony?

A26. Yes, it does.

VERIFICATION

I, Kelly R. Carmichael, Director of Environmental Permitting and Regulatory Services for NiSource Corporate Services Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Kelly R. Carmichael

Kelly R. Carmichael

Date: August 18, 2008